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PB-250 003

ENERGY DEVELOPMENT: THE ENVIRONMENTAL TRADEOFFS

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OCTOBER 1975

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ENERGY DEVELOPMENT: THE ENVIRONMENTAL TRADEOFFS

VOLUME 4: BACKGROUND PAPERS

by . . .
Mark D. Levine, Robert V. Steele, and Irving W. Yabroff

BACKGROUND PAPERS:

- Technological Overview
- Social Impacts of Energy Development in a Rural Area: A Case Example of Western Coal Development
- Water Availability and Consumption for Energy
- Water Pollution Potential of Energy Conversion Processes
- Air Pollution Impacts of Energy Production

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5

BIBLIOGRAPHIC DATA SHEET

1. Report No.

2.

3. Recipient's Accession No.

4. Title and Subtitle
Energy Development: The Environmental Tradeoffs
Volume 4: Background Papers

5. Report Date
October 1975

6.

7. Author(s)
Mark D. Levine, Robert V. Steele, Irving W. Yabroff

8. Performing Organization Rept. No.

9. Performing Organization Name and Address
Stanford Research Institute
Menlo Park, CA 94025

10. Project/Task/Work Unit No.
SRI Proj. No. 3563

11. Contract/~~Grant~~ No.
68-01-2469

12. Sponsoring Organization Name and Address
Office of Planning and Evaluation
U.S. Environmental Protection Agency
Washington, DC 20460

13. Type of Report & Period Covered

14.

15. Supplementary Notes

Energy and Environment Series

16. Abstracts

Volume four of the series contribures background information directly relevant to the analysis of environmental tradeoffs among the different measures to increase U.S. energy supply. Subject covered include: Technological Overview; Social Impacts of Energy Development in a Rural Area: A Case Example of Western Coal Development; Water Availability and Consumption for Energy; Water Pollution Potential of Energy Conversion Processes; Air Pollution Impacts of Energy Processes.

17. Key Words and Document Analysis. 17a. Descriptors

Liquid fuel supplies
Oil shale
Coal Liquefaction
Outer Continental Shelf
Assisted Recovery
Pipeline Gas

17b. Identifiers/Open-Ended Terms

17c. COSATI Field/Group

PRICES SUBJECT TO CHANGE

18. Availability Statement
unlimited

19. Security Class (This Report)
UNCLASSIFIED

20. Security Class (This Page
UNCLASSIFIED

21. No. of Pages
132

22. Price
$6.00 - 2.25

FORM NTIS-35 (REV. 10-73) ENDORSED BY ANSI AND UNESCO. THIS FORM MAY BE REPRODUCED USCOMM-DC 8265-P74

STANFORD RESEARCH INSTITUTE
Menlo Park, Cali[illegible]a 94025 · U.S.A.

October 1975

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CONTRACT NO. 68-01-2469
SRI PROJECT NO. 3563

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PREFACE

This report, entitled "Background Papers," constitutes the fourth volume of four in the series "Energy Development: the Environmental Tradeoffs." These reports have been repared for the Office of Planning and Evaluation of the U.S. Environmental Protection Agency. Their purpose is to clarify issues relating to critical environmental tradeoffs among options to increase domestic energy production. The reports have been designed to provide an initial assessment of factors that can influence policymakers and interested citizens in their judgments of relative rankings of energy supply options with respect to environmental and social impacts. The four volumes of the report should be read with a full understanding that this assessment process is in its early stages and that much more work of this kind needs to be done before firm judgments can be supported by an adequate data base and careful analysis. We have issued these reports in the anticipation that they will contribute significantly to useful and enlightened debate on the relative environmental impacts of alternative methods of energy extraction and conversion.

Volume four of the series contributes background information directly relevant to the analysis of environmental tradeoffs among the different measures to increase U.S. energy supply. Subjects covered include:

- Technological Overview
- Social Impacts of Energy Development in a Rural Area: A Case Example of Western Coal Development
- Water Availability and Consumption for Energy
- Water Pollution Potential of Energy Conversion Processes
- Air Pollution Impacts of Energy Processes.

ACKNOWLEDGEMENTS

This volume of the series "Energy Development: the Environmental Tradeoffs" was the result of a collaboration among Mark D. Levine, Robert V. Steele, and Irving W. Yabroff. Dr. Levine was the project leader for the study and is directly responsible for section II, Social Impacts of Energy Development in a Rural Area: a Case Example of Western Coal Development as well as parts of section VI, Air Pollution Impacts of Options to Increase U.S. Energy Supply. Dr. Steele is the author of section II, Technology Overview, and much of section VI. Dr. Yabroff wrote section IV, Water Availability and Consumption for Energy in the Colorado and Missouri River Basins, and section V, Water Pollution Potential of Oil Shale and Coal Conversion Processes.

Assistance in the form of reviews and research were provided by Steven H. Traver, Buford R. Holt, Barry L. Walton, Evan E. Hughes, and Jerry L. Jones. Larry H. Oppenheimer, the EPA project officer, contributed many valuable suggestions throughout the study. Supervisory assistance was provided by Stephen L. Brown and Robert M. Rodden. Madeline J. Anderson typed and proofread the draft. The editor was Phyllis F. Dorset.

Inquiries regarding the information presented in this or other volumes of the series "Energy Development: the Environmental Tradeoffs" should be directed to Robert M. Rodden (415) 326-6200, Ext. 3959; Mark D. Levine (415) 326-6200, Ext. 3157; or John Butler of EPA (202) 755-2733.

I. INTRODUCTION

In volume two of this report the environmental tradeoffs involved in developing new domestic energy supplies were analyzed to establish relative environmental rankings for the energy options. A considerable body of information regarding energy technologies and their environmental impacts was referred to or presented in summary fashion in this analysis. Information is presented in this volume to provide an in-depth assessment of selected social and environmental impacts of new energy development activities.

The purpose of the following sections is to illuminate problems associated with energy development in general (e.g., effects of urbanization and water availability in the West) as well as impacts resulting from a specific technology (e.g., emissions to the air from Lurgi coal gasification; the water pollution potential of oil shale processing). When possible, we have assigned quantitative values to specific impact categories. In the absence of quantitative information, we have provided a qualitative discussion of the expected magnitude of the impacts.

Section II presents an overview of the technologies to increase domestic energy supplies that we have analyzed in the study. Specific environmental and social impacts are not discussed in this chapter. Rather, details of the technologies are explained and expected trends in future energy development are indicated to provide a background for understanding technology-related environmental impacts. Wherever appropriate, aspects of a particular technology which will result in reduction of environmental disruption are pointed out.

Sections III through VI analyze issues associated with the specific environmental impact categories used in the environmental tradeoff analysis of volume two. The discussion focuses on aspects of the environmental impacts that are most relevant to the tradeoff analysis of volume two, providing also background information on how various emission estimates were arrived at.

Section III presents a discussion of the impacts of urbanization from energy development in the West, focusing on case histories of boom towns in Wyoming. The purpose of this section is to indicate some of the more serious problems that can arise under conditions of rapid energy development in essentially rural areas. Since many of the current energy development plans envisage resource extraction and conversion in frontier areas, unresolved issues associated with social impacts in rural and wilderness areas are particularly germane to an environmental assessment of energy strategies for the United States. The discussion in section III suggests a need for considerable analysis of possible mechanisms for minimizing adverse social impacts of energy development in such areas as the western United States.

Section IV examines the potential water availability for energy development in the Colorado and Missouri River Basins based on instream flow requirements and projected future growth of energy and non-energy related uses. The analysis suggests that the competition between energy and non-energy uses of the scarce water resources in the West is a critical issue that will have significant impact on the nature of future development in the West. To the extent that forms of energy development that consume large quantities of water continue their growth in the West, limited water availability is likely to constrain the growth of other activities, such as agriculture. Water availability is particularly limited in the Colorado River Basin.

Sections V and VI analyze in detail the emissions of pollutants to the water and the air, respectively, from the various technologies discussed in section II. Of particular note in section VI is the standardization of assumptions regarding environmental control for different energy technologies, as summarized in Tables VI-1 through VI-3. Section VI also treats the emissions of trace elements from the combustion of coal, and develops a simple model for estimating the significant environmental impacts of specific trace elements.

II. TECHNOLOGICAL OVERVIEW

This chapter is intended to explain the technologies whose environmental impacts have been evaluated in preceding chapters. It focuses on the processes involved in energy conversion and discusses the technological alternatives for carrying out each type of conversion. It presents a state-of-the-art view of the technologies, indicating many of the projects currently underway to further develop the technologies and the areas in which research efforts are being pursued.

A. Technologies for Increasing the Production of Electricity from Western Coal

The two technologies under consideration for generating electricity from western coal are: (1) direct burning of coal to produce steam, which drives a steam turbine, and (2) low-Btu gasification of coal followed by utilization of the gases in a gas-turbine/steam-turbine combined-cycle system. The technology of electricity production via coal-fired boilers and steam turbines is well established, and thermal efficiencies of the order of 35 percent are typically achieved. The upper limit of efficiency for this type of power generation is approximately 40 percent. This limit is a thermodynamic one imposed by the difficulty of producing steam in coal-fired boilers at temperatures much above 1000°F.[1] Due to the fact that some power must be used to run auxiliary equipment, such as stack gas cleanup systems, it is unlikely that efficiencies in excess of 38 percent will be achieved. However, improvements may be expected to occur in related areas such as air pollution control, waste heat disposal and efficiency of electricity transmission.

An improvement in coal combustion, which may significantly reduce the size and cost of boilers as well as their atmospheric emissions, is the fluidized bed combustion process. In this process, crushed coal is conveyed to the boiler by preheated air. Additional air is injected into the boiler bed to create turbulent motion (fluidization). Combustion takes place at about 1500°F, allowing placement of heat transfer surfaces or boiler tubes within the fluidized bed.[2] This relatively low combustion temperature reduces NO_x emissions. Addition of lime (CaO) or limestone ($CaCO_3$) particles to the bed causes the SO_2 formed during combustion to be converted to $CaSO_4$, which greatly reduces emissions of this pollutant and allows high-sulfur coal to be used.

Both atmospheric pressure and pressurized versions of the fluidized bed boiler are being tested. Westinghouse is planning a 635-MW plant in Pittsburgh, Pennsylvania, using a pressurized boiler, while Pope, Evans, and Robbins propose to build a 30-MW atmospheric pressure unit in Alexandria, Virginia. The advantage of the pressurized process is that the high pressure combustion gases may be used to drive a gas turbine after they leave the combustor, provided particulate matter and SO_2 are reduced to very low levels.

The use of low-Btu gas in combined-cycle operation has not yet been used in this country due to high operating costs and the low efficiency of present gas turbine technology. However, such a system, including a Lurgi gasifier, has been installed at Lünen, West Germany; the capacity of this system is 172 MW (74 MW is generated by the gas turbine and 98 MW is generated by the steam turbine). In addition, a number of combined-cycle systems operating on natural gas and distillate fuels have been installed in the United States for peak load applications.

Several experimental or demonstration projects are underway to study the production of low-Btu gas followed by electric power generation. Under

Office of Coal Research sponsorship, Combustion Engineering and Consolidated Edison (Con Ed) will evaluate various gasification/power generation combinations and build a pilot plant gasifier to obtain scale-up data for commercial operation in Con Ed facilities. Commonwealth Edison is building a demonstration plant in Illinois, using Lurgi technology (discussed below) to provide low-Btu gas for a 70-MW power plant. In another Office of Coal Research sponsored project, Pittsburgh and Midway Coal Company is building a 50-ton/hr gasifier, which will provide fuel to drive a gas turbine generator.

In discussing the technology of low-Btu gasification/combined cycle systems it is natural to examine the two component systems separately since the choice of gasification process, for example, has little effect on combined cycle operation. A simplified flow diagram of the two component systems is shown in Figure II-1.

The process of low-Btu gasification of coal has been known for many years and was first used to provide "town gas" for residential use until natural gas became widely available. The gasification process essentially involves the controlled reaction of coal with steam and air to produce a gas of low heating value (100-200 Btu/SCF) whose major reactive constituents are CO (carbon monoxide) and H_2 (hydrogen). Following gasification, the product gases are cooled and scrubbed to remove tars, oil, and particulate matter, and may be further treated to remove sulfur compounds. The resulting product gas is suitable as a fuel for power generation if it is consumed at a location near the gasification plant. Because of its low heating value (one-tenth to one-fifth that of natural gas), it is uneconomical to transport the gas over long distances via pipeline.

Two coal gasification processes, which are typical of those available in this country, are the Lurgi and the Koppers-Totzek (see Table VII-1,

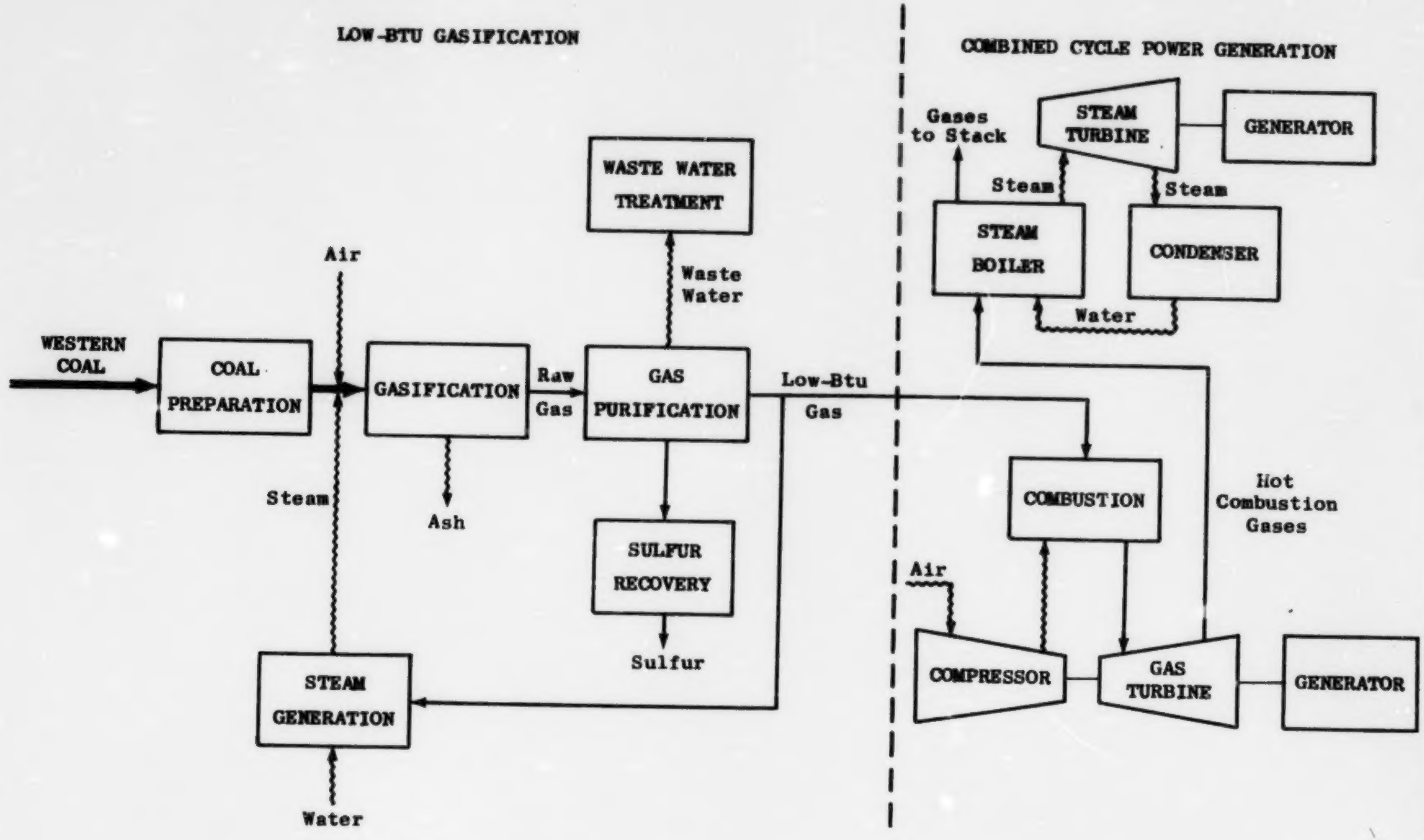
LOW-BTU GASIFICATION
COMBINED CYCLE POWER GENERATION
WESTERN COAL
COAL PREPARATION
Air
Steam
GASIFICATION
Ash
Raw Gas
GAS PURIFICATION
Waste Water
WASTE WATER TREATMENT
SULFUR RECOVERY
Sulfur
STEAM GENERATION
Water
Low-Btu Gas
Gases to Stack
STEAM BOILER
Steam
STEAM TURBINE
GENERATOR
Steam
CONDENSER
Water
COMBUSTION
Hot Combustion Gases
Air
COMPRESSOR
GAS TURBINE
GENERATOR

FIGURE II-1. LOW-BTU GASIFICATION/COMBINED CYCLE POWER GENERATION

Section C). In the Lurgi process,[3] crushed coal is fed in a batch into the top of the reactor and steam and air are injected at the bottom. Gasification takes place at high temperature and pressure (1400°F and 400 psi). Ash is removed through a grate at the bottom of the reactor. The Lurgi gasifier is termed a "fixed bed" reactor since the coal remains fixed in place as gasification is carried out.

The Koppers-Totzek gasifier operates in a different manner.[3] Coal is first pulverized to a fine powder and injected into the reactor along with streams of oxygen and steam via two opposing nozzles. Gasification occurs in the middle of the reactor at very high temperatures (around 3000°F) and atmospheric pressure. The product gases exit at the top of the reactor, and the molten ash falls to the bottom where it is captured in a bed of water. Because of the high temperature required for gasification, air cannot be used in place of oxygen. This type of gasifier is termed an "entrained bed" reactor since the finely divided coal particles are entrained in the steam/oxygen stream.

In spite of their commercial availability and long history of use, there are several drawbacks to both processes. The Lurgi process does not operate well with highly caking coals, such as those found in the eastern United States, and has problems with clinker formation, which can plug the grate at the bottom of the bed. Moreover, a quenching step is required before further processing can take place because of the high content of oil and tars in the product gas. The quenching step is not favorable to efficient utilization of the gas since the efficiency of combustion of fuel gas in a gas turbine is increased at higher temperatures. The main drawbacks of the Koppers-Totzek process are the necessity of using oxygen and operation at atmospheric pressure. Oxygen plants are expensive and require additional energy to operate, and thus introduce another inefficiency into the system. Even more energy is required to compress the fuel gas prior to combustion in a gas turbine, which takes place at high pressures.

Several new gasification technologies are under development that eliminate most of the drawbacks of the Lurgi and Koppers-Totzek processes. One of the most promising is the ash-agglomerating fluidized bed gasifier.[4] In this process, coal is fed by gravity from the top of the reactor, and high pressure steam and air are injected at the bottom at high velocity. These high velocity streams keep the coal particles in constant motion, resulting in a uniform temperature throughout the bed of around 2000°F. As ash is formed, it agglomerates in small lumps, which gravitate to the bottom of the bed where they are removed. As in the Lurgi process, gasification takes place at high pressures. However, due to the more complete combustion of volatile materials within the bed, no tars or oil are formed, thus eliminating the need for quenching of the product gas. In addition, the product gas contains relatively more CO and H_2 and less water vapor and CO_2 than that from the Lurgi process. Pilot plant gasifiers based on the fluidized bed principle have been built and tested by the Westinghouse Research Laboratories and by Arthur Squires at the City University of New York, among others.

At present, combined-cycle systems using gas and steam turbines fueled by low-Btu gas are not competitive with direct combustion of coal in terms of either cost or efficiency. This is due primarily to the low efficiency of present technology gas turbines. Gas turbines in current use for peak load application operate on natural gas or distillate fuels and typically have efficiencies of around 25 percent.[4] The purpose of combined-cycle operation is to utilize the heat in the exhaust gases from the gas turbine to raise steam which can be used in a conventional steam turbine to produce additional electricity. The limitation on efficiency of both the gas turbine and the overall combined-cycle system is the temperature at which combustion gases enter the turbine. Gas turbine inlet temperatures are currently limited to 1850°F. This is due to both the strength of materials used in the turbine blades and the technology for cooling the blades. At this inlet temperature, a combined-cycle system can operate at about 40 percent efficiency if half the electricity is generated by the gas turbine and half by the steam turbine.[1] On the basis of projections by gas turbine manufacturers, it is expected that by the early to mid-1980s improvements in turbine blade materials and cooling techniques will permit inlet temperatures near 2800°F.[1] At this temperature, a combined-cycle system could be operated at 50 percent efficiency. If this system were operated with a gasifier of 75 percent efficiency, an overall efficiency of about 38 percent could be achieved, comparable to that currently achieved with direct combustion. Due to this improvement in efficiency, costs are also expected to be competitive with direct combustion in the mid-1980s, especially if the costs of stack gas cleanup are included in the cost of a direct combustion power plant.

B. Technologies for Increasing Liquid Fuel Supplies

1. Oil Shale

The major attraction of oil shale development is the large quantity of resource, which is potentially available for recovery. It is estimated that recoverable reserves of oil shale in Utah, Wyoming, and Colorado containing at least 30 gallons of kerogen per ton of shale, in beds at least 30 feet thick, can yield over 130 billion barrels of oil.[5] This is 20 times the current annual U.S. consumption, an amount equal to the total estimated conventional U.S. oil reserves. However, the cost of recovering this oil is high. On the average, 1.4 tons of shale must be mined, crushed, processed and disposed of for each barrel of oil recovered. Thus, an oil shale plant producing 50,000 barrels of oil per day must handle 25 million tons of shale per year. This is five times the amount of material mined in the largest underground coal mines now in operation.

It is anticipated that most of the shale will be extracted from underground mines by means of the room-and-pillar method. With this technique, about 60 percent of the in-place resource can be recovered and 40 percent is left in the form of pillars to support the roof of the mine. Room-and-pillar mining is sufficiently well developed that no significant technical problems are foreseen in the extraction stage of oil shale recovery.

Conceptually, the technology for obtaining liquid hydrocarbons from oil shale is a simple one. The crushed shale is heated in a closed vessel (retort) to a temperature of 900°F or greater, at which point the kerogen vaporizes and is separated from the solid inorganic portion of the rock. After retorting, the shale oil is upgraded by means of hydrotreating (chemically reacting with hydrogen) to yield a low-viscosity product which is suitable for transport via pipeline and can be used as a refinery feedstock.

A simplified flow diagram of oil shale retorting and upgrading is shown in Figure II-2. Fractionation of the shale oil product separates hydrocarbon gases and the different oil fractions--naphtha, gas oil and residual oil. The gases are first treated to remove sulfur compounds; most of the gases are then used as plant fuel and the remainder are sent to the steam reformer to be converted into hydrogen. The residual oil is sent to a coking unit where coke is produced along with additional gas oil and naphtha which are returned to the fractionator. The naphtha and gas oil streams are hydrotreated separately, then combined to give synthetic crude oil. Foul water produced in the hydrotreaters is sent to a stripper where hydrogen sulfide is removed and sent to sulfur recovery and ammonia is recovered as a byproduct.

The various methods for retorting oil shale differ in the manner in which heat is generated and transferred to the shale. The simplest method is the Fischer assay technique in which heat from an external fire

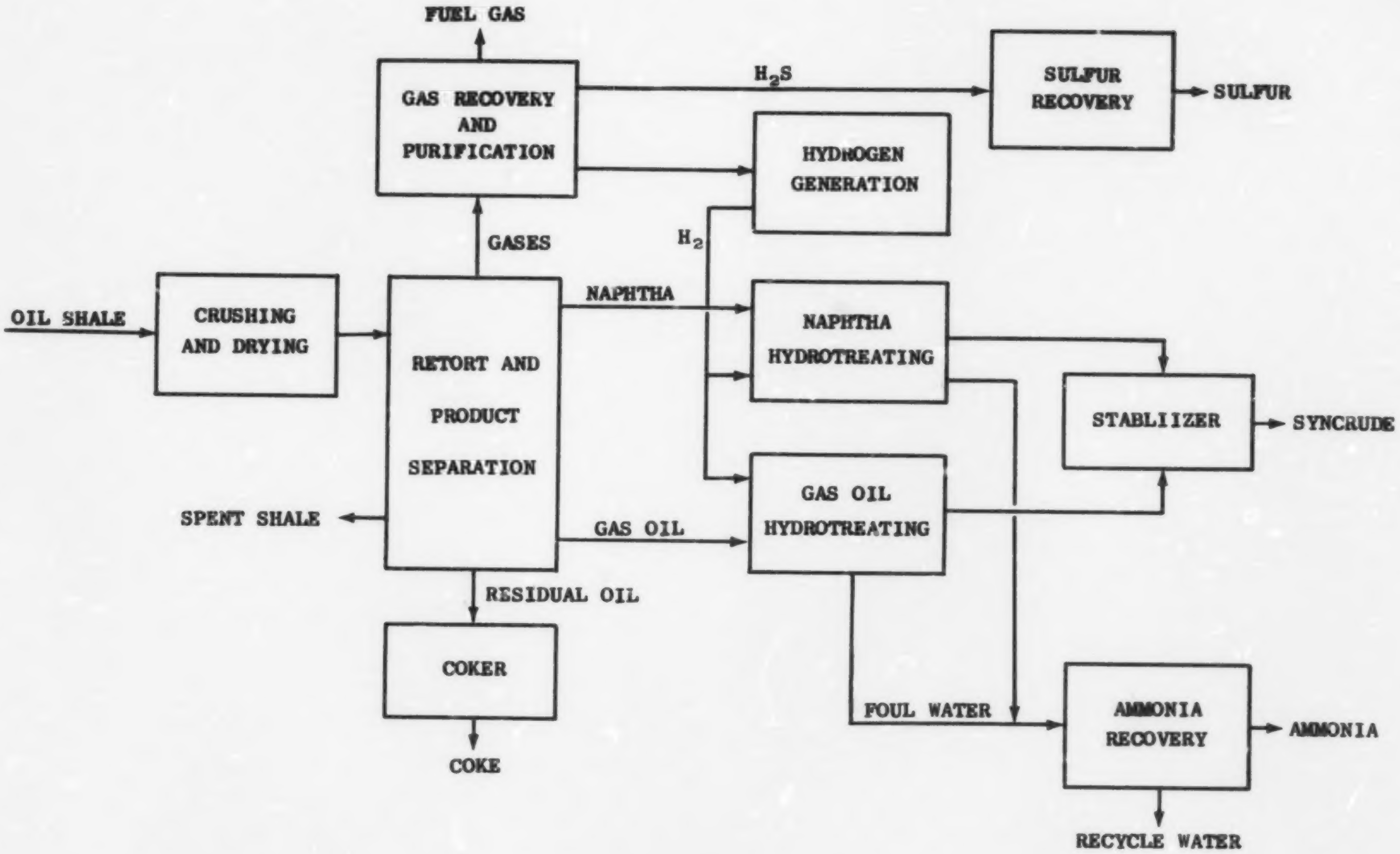
FUEL GAS
GAS RECOVERY AND PURIFICATION
H_2S
SULFUR RECOVERY
SULFUR
HYDROGEN GENERATION
GASES
H_2
OIL SHALE
CRUSHING AND DRYING
RETORT AND PRODUCT SEPARATION
NAPHTHA
NAPHTHA HYDROTREATING
STABLIIZER
SYNCRUDE
SPENT SHALE
GAS OIL
GAS OIL HYDROTREATING
RESIDUAL OIL
COKER
COKE
FOUL WATER
AMMONIA RECOVERY
AMMONIA
RECYCLE WATER

FIGURE II-2. OIL SHALE RETORTING AND UPGRADING

is transferred to the shale through the wall of the retort. Any fuel may be used to supply the heat. Due to large capital and operating costs, this method is unsuitable for commercial development. It is, however, commonly used on a laboratory scale to measure the kerogen content of the shale.

There are four additional methods for retorting oil shale which are in various stages of development and which have the potential for commercial application.[6,7] These are discussed in the following paragraphs.

a. Hot Solids or Solids-to-Solids Heating Method

The TOSCO II process is the most advanced version of this technique. In this process, ceramic balls are heated by the combustion of byproduct gases and liquids and transferred to the retort where they are mixed with crushed, preheated shale. Shale oil vapor is driven off and recovered. The ceramic balls are size separated from the spent shale and subsequently reheated. A high efficiency of energy recovery is achieved; however, capital and operating costs are high.

In the Lurgi-Ruhrgas version of this technique, which has been tested in a 12 ton-per-day pilot plant in West Germany, spent shale is used as the heat carrier. The spent shale is heated by combusting the carbon residue which remains after retorting, together with additional fuel as needed.

The TOSCO II process is essentially ready for commercial application. Colony Development Operation (a joint venture of ARCO, Ashland, Shell, and The Oil Shale Corporation) has successfully completed tests on a 25 ton-per-day test unit and an 1100 ton-per-day semiworks plant at Parachute Creek, Colorado. Colony had announced plans to begin construction in April 1975 of a 50,000 bbl-per-day commercial plant based on the TOSCO II process. These plans were later postponed, with Colony citing rapidly inflating construction costs and uncertainties in U.S. energy policy as the basis for its decision.

There are several other planned commercial operations in which the TOSCO II retort will be used. These include the following: a 50,000 bbl-per-day operation planned for startup in 1982 by ARCO, TOSCO, Ashland, and Shell as a joint venture on Colorado Tract C-b; the Rio Blanco Oil Shale Project, a joint venture on Colorado Tract C-a by Gulf Oil and Standard of Indiana with 50,000 bbl-per-day initial production planned for 1980; the 75,000 bbl-per-day Sand Wash Project in Utah planned by TOSCO with startup expected in 1981-83.

b. Gas-to-Solids Heating/Internal Gas Combustion

In this method, crushed shale is fed to the top of a vertical retort and low-Btu byproduct gas is injected at the bottom. The gas is combusted in the retort along with residual carbon on the spent shale; the hot combustion gases heat the shale, driving off the oil vapors, which are condensed at the top of the retort. The noncondensable gases are recycled for combustion. Due to the lack of external heating equipment, this method is less costly than other types of retorts. Energy recovery efficiency is somewhat lower, however.

The Bureau of Mines tested a version of this technique, called the Gas Combustion process, in 1966-67. No tests have been carried out on this process since then.

The Union Oil Company version of the process utilizes a unique "rock pump," which injects at the bottom of the retort while combustion gases are drawn down from the top by blowers and retorted shale oil is collected at the bottom. A 1000 ton-per-day pilot plant was successfully demonstrated in 1957-58. A more advanced version of this retort, called the steam gas recirculation (SGR) process, was recently announced and a 1500 ton-per-day demonstration plant based on this process will be built on private land in Colorado. (The SGR retort is actually an example of the gas-to-solids, external heat generation method discussed in the next section.) Union plans to have a 50,000 bbl-per-day commercial plant operating by 1980.

A third variation on the process has been constructed by Development Engineering, Inc. (DEI), the operating arm of Paraho Development Corporation (a consortium of 17 firms). This process, usually referred to as the Paraho retort, utilizes patented shale-feed and spent shale-discharge grates, which provide a uniform flow of shale through the retort. Multi-level gas injectors are also used to carefully control the level of incoming gases. DEI recently completed a successful 30-day run on its 500 ton-per-day test plant near Rifle, Colorado, as part of a 30-month R&D program. Paraho has also proposed constructing and testing of a commercial-sized retort on the Naval Oil Shale Reserve in Colorado.

Both of the planned commercial operations on federally leased tracts in Utah use primarily the Paraho retort, although finely crushed shale (10 to 20 percent of the total) will be retorted by the TOSCO II process, since the Paraho retort can operate only on coarse shale. Sun Oil and Phillips Petroleum have leased the Utah U-a tract and propose to have a 50,000 bbl-per-day plant operating by 1978. The White River Shale Corporation (a joint venture of Sun, Phillips, and Standard of Ohio) has leased the other Utah tract (U-b) and is also planning a 50,000 bbl-per-day operation. Due to the contiguity of the two tracts, and overlapping ownership in the two ventures, it is likely that these operations will be carried out jointly by all the participants.

c. Gas-to-Solids Heating/External Heat Generation

This method calls for recirculated byproduct gas to be used as the medium of heat transfer; however, heating of the gas is carried out in an external furnace, rather than by combusting the gas and spent shale within the retort. Some of the byproduct gas, carbon residue on the spent shale, or any other suitable fuel may be combusted to supply heat to the furnace. During 1975, Paraho will begin testing a version of its retort, which operates with externally heated gases.

The Brazilian national oil company (Petrobras) has tested a 2200 ton-per-day version of the external gas heating retort called the Petrosix process. The tests were successful; however, there are no plans for commercial application in the United States.

d. In-Situ Retorting

In in-situ retorting, shale rock is fractured in place by explosives to form an underground retorting chamber. Air is injected to combust part of the shale, and retorting is carried out via heat transfer from the hot combustion gases. Shale oil is collected from a hollow mined at the bottom of the shale column.

Numerous tests of this method have been made by various companies. Commercial feasibility has not yet been demonstrated, although recent tests by Garrett Research and Development, a subsidiary of Occidental Petroleum, appear promising. A 30x30x70-ft shale column was successfully retorted, resulting in a shale oil yield of about 60 percent. Further tests are planned on a 100x100x250-ft column, with yields expected to be in excess of 70 percent.[8] If the Garrett or other tests demonstrate the commercial feasibility of in-situ retorting, the use of this method could considerably reduce water consumption, spent shale disposal, and other problems presently associated with above-ground retorting. However, new problems, such as surface subsidence and the release of large quantities of combustion gases, would be created, and these would need to be dealt with carefully. This method is expected to be less costly than any above-ground retorting technique.

2. Coal Liquefaction

The process of converting coal into liquid fuel has great potential for contributing to future domestic fuel supplies because of the enromous reserves of coal that are available for extraction. Each ton of coal can yield up to three barrels of synthetic crude oil or other hydrocarbon products. Most of the sulfur in the coal is removed during liquefaction so that even high-sulfur (3-4 percent) midwestern coal can be converted to low-sulfur (0.2-0.5 percent) fuel.

To date, no commercial coal liquefaction plants have been planned since the technology is not at a sufficient level of development to bring a commercial plant on stream with any reasonable guarantee of success. However, a number of pilot plants are being operated, generally under sponsorship of the Office of Coal Research, and several demonstration plants are in the planning stages. It is generally believed in the industry that no full-sized commercial plants (30,000 bbl-per-day or larger) will be on-line much before 1985.

The processes for converting coal to liquid fuels fall into three main categories. These are: gasification/Fischer-Tropsch synthesis, pyrolysis, and coal dissolution. Gasification of coal followed by Fischer-Tropsch synthesis to yield gasoline and other hydrocarbon byproducts[3] is the only one of the three processes that is currently in commercial operation--a 6600 ton-per-day plant is being operated by the South African Gas and Oil Company (SASOL). In the first step of the process, coal is gasified in the presence of steam and oxygen (see discussion of high-Btu gasification) to produce a synthesis gas consisting mainly of carbon monoxide and hydrogen. The synthesis gas is purified and then reacted catalytically to yield liquid hydrocarbons. Although synthetic gasoline is the primary product, a variety of byproducts, such as oils, alcohols and waxes, are produced as well. Due to the high costs and low efficiency of this technique, it is unlikely that it will be utilized to any significant degree in the United States.

Coal pyrolysis is a technique for extracting oil, gas, and char (a solid product consisting mostly of carbon and ash) from coal by heating it to high temperatures in the absence of air. In the COED (Char-Oil-Energy-Development) process developed by the FMC Corporation, crushed coal is heated in four successive stages from 600 to 1600°F. In the last two stages, some of the char is combusted to provide hot gases for heating the first two stages. The oil and gases result from driving off the volatile organic matter in the coal, primarily in the first two stages. Hydrogen derived from the medium-Btu byproduct gas is used to upgrade the oil to a synthetic crude oil. The syncrude yield is about one barrel per ton of coal input.[3] The COED process has been tested in a 36 ton-per-day pilot plant near Princeton, New Jersey. Other coal pyrolysis methods have been tested at the pilot plant stage by Garrett Research and Development and the Oil Shale Corporation. In all pyrolysis methods, the yield of oil is low compared with the other methods for making liquid fuels from coal.

The method of coal dissolution (also known as solvent refining or solvent extraction) has the greatest potential for efficiently producing liquid hydrocarbon fuels from coal.[9] The two basic steps in this process are the dissolution of the organic matter in the coal in a process-derived solvent, and hydrogenation of the resulting product to yield a liquid hydrocarbon fuel (see Figure VII-3. Dashed lines indicate the different stages at which hydrogenation can take place.). The three variants of the coal dissolution method, which have been most extensively tested, are the Solvent Refined Coal (SRC) process of Pittsburgh and Midway Coal Company, the Consol Synthetic Fuel (CSF) process of Consolidation Coal Company, and the H-Coal process of Hydrocarbon Research, Incorporated.

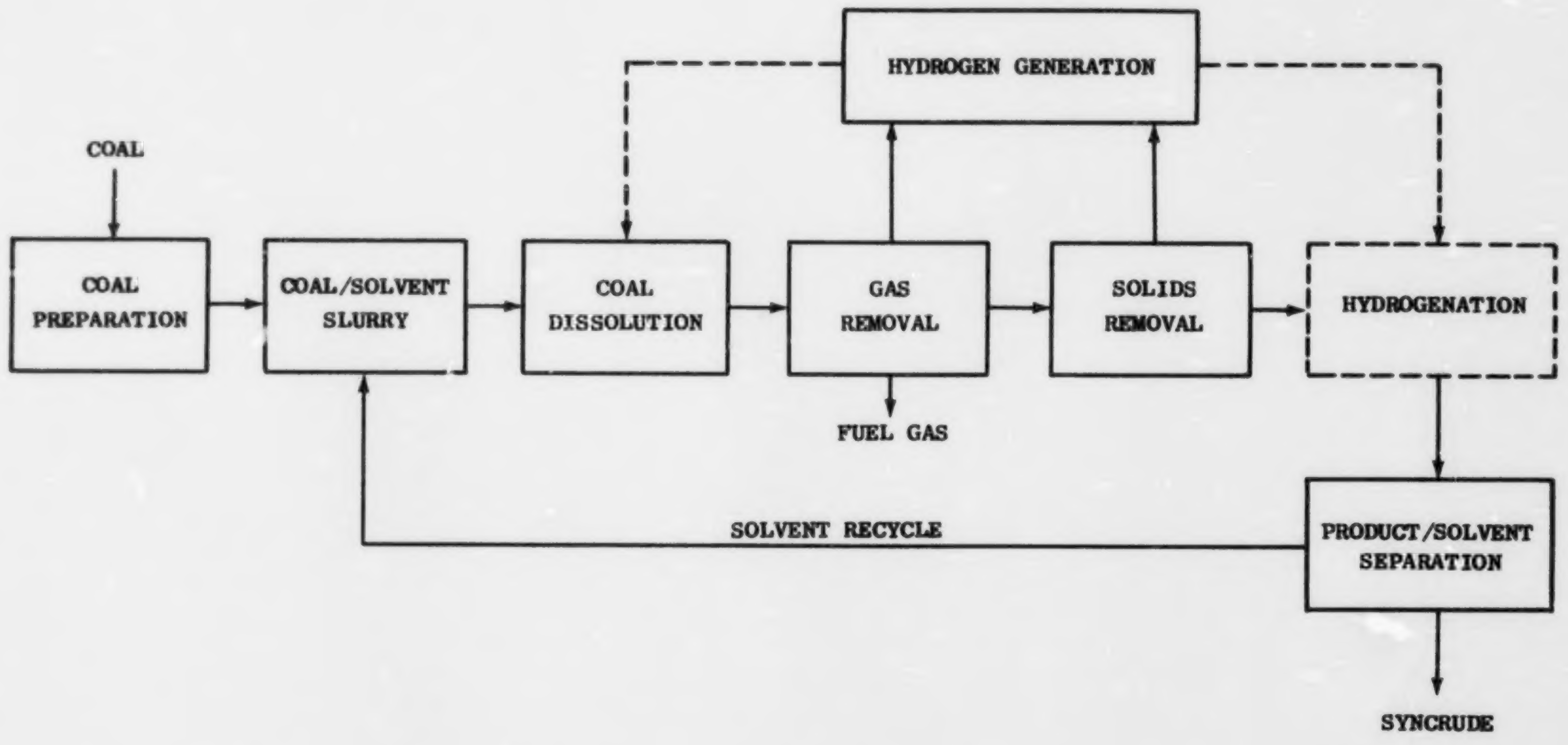
COAL
COAL PREPARATION
COAL/SOLVENT SLURRY
COAL DISSOLUTION
GAS REMOVAL
SOLIDS REMOVAL
HYDROGENATION
HYDROGEN GENERATION
FUEL GAS
SOLVENT RECYCLE
PRODUCT/SOLVENT SEPARATION
SYNCRUDE

FIGURE II-3. COAL LIQUEFACTION VIA DISSOLUTION AND HYDROGENATION (FROM REFERENCE 9)

In the SRC process, the crushed coal is first slurried with the solvent and then reacted with hydrogen at 815°F and 1000 psi, causing complete dissolution of the organic matter. After separating unreacted solids and solvent, a low-sulfur, ash-free product, which is a solid at room temperature, is obtained. It must be further upgraded by hydrotreating to yield synthetic crude oil. Two pilot plants have been constructed to test the SRC process. A six ton-per-day plant producing a clean boiler fuel recently completed a 75-day test run at Wilsonville, Alabama. Sponsors are the Electric Power Research Institute and the Southern Services Company. In Tacoma, Washington, a 75 ton-per-day pilot plant has been built by Pittsburgh and Midway under the sponsorship of the Office of Coal Research.

The CSF process separates the dissolution and hydrogenation steps. The crushed, dried, and preheated coal is first slurried with a hydrogen donor solvent. Then it is passed through a tubular furnace at 150 psi and 765°F to an extraction vessel where dissolution of the organic matter is completed. After unreacted solids are separated, the resulting liquid is fractionated. The low-boiling fraction is recovered as solvent, and the heavy bottom product is further hydrogenated at 800°F and 3000 psi to yield naphtha and fuel oil products.

A 70 ton-per-day pilot plant based on the CSF process was operated at Cresap, West Virginia, for 40 months, ending in 1970. Because of recurring equipment failures, the plant was shut down for a detailed study of problem areas. It was concluded, however, that the process, as designed, is technically feasible. This plant is scheduled to be reactivated by the Fluor Corporation; several coal-to-liquid-fuel processes will be tested.

A third variant of the solvent refining method, the H-Coal process, carries out dissolution and hydrogenation in the same step in the presence of a catalyst. The slurried coal is reacted with hydrogen in an ebullating bed reactor at 850°F and 2700 psi. A cobalt-molybdenum catalyst is continuously added to the reactor as spent catalyst is removed. After separating gases and unreacted solids from the mixture, synthetic crude oil is recovered from fractionation of the resulting liquid.

Initial testing of the H-Coal process has been carried out in a 3 ton-per-day pilot plant at the Hydrocarbon Research, Inc. (HRI) facilities at Trenton, New Jersey, under the sponsorship of Ashland, ARCO, Standard of Indiana, and Exxon. In addition, the Office of Coal Research and HRI are planning a 600 ton-per-day pilot plant at Catlettsburg, Kentucky, to test the commercial feasibility of the H-Coal process. Industrial sponsors include those mentioned above (except Exxon), the Electric Power Research Institute, and Sun Oil.

In all of the coal dissolution processes discussed above, large amounts of hydrogen (15,000 to 20,000 SCF per ton of coal) are consumed. In general, the hydrogen can be supplied by gasifying unreacted coal solids (char) or steam reforming byproduct hydrocarbon gases. If necessary, additional hydrogen can be provided by gasifying some of the feed coal.

Several additional variants of the coal dissolution method are being tested. Gulf Research and Development recently began testing a catalytic process in a 1 ton-per-day pilot plant. The Bureau of Mines has contracted Foster-Wheeler Corporation to design an 8 ton-per-day pilot plant to test its Synthoil process, which is similar to the H-Coal process, and has been tested through the 1/2 ton-per-day pilot plant stage.

In addition to the three types of processes discussed above, a number of companies are carrying out research and development activities to test, improve, or demonstrate coal liquefaction processes of their own design. These activities include the following: design of a 300 ton-per-day pilot plant by Exxon at its Baytown, Texas, refinery; design of a 900 ton-per-day demonstration plant by Old Ben Coal Corporation (Standard Oil subsidiary); COGAS Development Company operation of a 100 ton-per-day pilot plant to produce oil and SNG from coal. The largest demonstration plant planned to date is the 2600 ton-per-day plant, which will be built by Coalcon under contract to the Office of Coal Research. Coalcon is owned jointly by Union Carbide and Chemical Construction Corporation. The plant is projected to produce 3900 barrels of liquid fuel and 22 million SCF of substitute natural gas per day, using a hydrocarbonization process developed by Union Carbide.

3. Technologies for Recovery of Oil and Gas from the Outer Continental Shelf

a. Geophysical Exploration

Prior to the call for nomination of lease sale tracts, the oil companies who place bids generally analyze the structural components of the Continental Shelf and slope to determine probable locations of hydrocarbon deposits. Preliminary analysis is accomplished by conducting measurements of changes in the magnetic and gravitational fields of the earth, and by observing locations of natural seeps. Site specific techniques, including seismic surveying, bottom sampling, and coring, are used to gain more specific information about an offshore region. In seismic surveying, the preliminary and most important phase of predrilling exploration, a series of small amplitude seismic pulses are transmitted through the water to the underlying strata of the ocean floor. On contact with the underlying strata, the pulses are reflected and refracted back through the water toward the ocean surface, where they are detected by hydrophones* and recorded on magnetic tape. The data are used to construct seismic profiles, which are interpreted to identify areas where sediments containing hydrocarbons may be located.

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* A hyprophone is a device containing a series of detectors, which receive and amplify reflected and refracted seismic pulses.

A more recent method, known as "bright spot technology," has evolved to improve seismic measurements. This improved method highlights certain sections of the earth's strata by selectively intensifying the amplitude of the seismic pulse. This technology has been more effective in locating gas deposits than oil-bearing strata due to the better reflective characteristics of gas-filled rocks.[10] Following the mapping of the underlying strata, bottom samples or core wells are used to a limited extent to determine the hydrocarbon potential of a specific site. For core wells, penetration has been limited to 1000 feet or less to reduce the possibility of blowouts.[11]

b. Exploratory Drilling

Following the purchase of a particular tract in a lease sale, offshore exploratory drilling is conducted. Three types of mobile platforms are commonly used in exploratory drilling: barges and ships, a platform mounted on an adjustable tripod that rests on the ocean floor (the "jack-up"), and a semisubmersible floating platform. Barges are used in shallow offshore areas and are limited in their use to times of mild weather and regions of weak currents. Jack-ups are used more often than barges in shallow waters. Use of this platform is limited to regions where the ocean depth is less than about 400 feet.[12] Drill ships and semisubmersible rigs can be used in water depths of 1000 feet and greater,[12] and provide a more stable drilling position than barges in deep water. Even with the use of the semisubmersible rig or drill ship, however, high seas and strong currents make it difficult to maintain the proper alignment of the rig with the drill hole.

The depths at which floating rigs have been used has steadily increased over the past several years. In the Santa Barbara

Channel, over 30 exploratory wells have been drilled at depths greater than 500 feet; four were at water depths approaching 1500 feet. Currently, Shell Oil Company is engaged in drilling off the coast of Gabon, Africa, at water depths of 2150 feet.

Offshore drilling methods, involving the use of a rotating drill contained within a metal pipe casing, are the same as those used onshore. Drilling muds are pumped through the drill bit to remove the cuttings from the drill face and to maintain an equilibrium with the pressure of the geologic formation. If the proper pressure of the drilling muds is not maintained, a blowout can occur. When this occurs, blowout preventers are supposed to seal off the well at the seabed surface.

c. Field Development

If exploratory operations are successful in proving the existence of a commercial hydrocarbon reserve, fixed platforms for production operations are installed. Pilings are driven through the structure legs into the ocean bedrock to secure the platform. Platforms of this type are currently installed in water nearly 500 feet in depth, with one being built for the Santa Barbara Channel to be placed in 850 feet of water.[12]

Buoyant towers are currently being developed for use in water depths of 1000 feet or greater. Unlike conventional fixed platforms, buoyant towers may not be used in waters much less than 1000 feet deep. These towers can sway under wave action.

An alternative production system to the fixed platforms or buoyant towers is the subsea production system (SPS). Two main types of SPS's have been designed. One such system provides for mechanics and technicians to work on the ocean floor in a capsule maintained at atmospheric pressure. The other system, currently under development, is a self-sustaining production facility which does not require subsurface operators. At present, two of these production systems are producing oil in the Gulf of Mexico and 70 subsea wellheads are currently in use. Even though these subsea systems have advantages at great depths, they can pose major problems. The subsea systems are harder to maintain in the event of an emergency due to their limited accessibility and the subsea systems can be snagged during trawling operations.

During production on a platform, downhole control devices, which contain velocity actuated safety valves located at least 100 feet below the sea floor, are of major concern if surface equipment fails. These valves are particularly susceptible to failure from internal corrosion and have failed to prevent recent accidents in the Gulf of Mexico and elsewhere. New types of valves, which are no longer actuated by well fluid velocities, are now used, at a considerable increase in cost.

d. Transportation of Produced Oil and Gas

At present, most production from offshore regions is transported by pipeline to onshore refining and storage facilities (California--100 percent, Gulf of Mexico--98 percent).[11] Plans for the development of petroleum resources within the 200-mile jurisdiction of the United States will continue to utilize some type of piping. However, in OCS development in the Gulf of Alaska, once oil has been piped ashore to terminal facilities, tankers will be required to ship the raw fuels to refineries along the Pacific coast.

Current methods of pipeline construction vary to some extent, but one method, pipe laying by barge, is most widely used. This method uses a self-contained barge, from which the pipe is welded, given a protective coating, and lowered into place. On completion of a section of pipeline, the barge is moved forward, which allows the assembled pipeline to extend over the rear of the barge and sag downward to rest on the ocean floor.

A second method of pipeline construction requires the construction of pipe sections onshore. Tugs and barges are then used to drag completed sections of pipeline to the offshore site. This technique requires large, unobstructed areas of shoreline. Such a method is rarely used for pipelaying to OCS sites.

All pipelines currently used are coated with epoxy compounds or thick asphaltic material to prevent corrosion. Cathodic protection methods are also employed. For mechanical protection and weighting of a pipeline system, a layer of dense concrete is applied over the anticorrosive materials.

As required by OCS administrative procedures, at depths less than 200 feet, pipelines must be buried to a minimum depth of three feet; in ship fairways and anchorage areas, the burial is at a minimum depth of 10 feet. Current burial methods involve the use of a water jet under high pressure, which turns up the bottom sediments under the pipeline and allows the pipe to settle into the resulting trench and be buried by the suspended sediments.

Transport of hydrocarbon fuels by tanker will increase as offshore development begins in the Atlantic and Alaskan OCS regions. Recent technological advances in the development of Very Large Crude Carriers (VLCC) have provided substantial economic advantages in shipping crude oil over great distances. Such supertankers are expected to transport oil between Alaska and the West Coast.

4. Technologies for Producing Oil Through the Use of Assisted Recovery

Four assisted recovery technologies promise the largest additional oil recovery over conventional production methods: hydrocarbon miscible, carbon dioxide miscible, thermal and micellar methods. Thermal and micellar methods are generally regarded as the most productive possibilities. Conventional oil recovery methods produce an average of about 30 percent of underground oil resources. Perhaps an additional 30 percent of the oil resources can be recovered using assisted recovery methods.[13] With cumulative U.S. production at about 100 billion barrels, an additional 100 billion barrels produced by assisted recovery would satisfy current U.S. demand of 17 million barrels per day for about 16 years. Less than 10 percent of this recovery is likely to be achieved by 1985.

Assisted recovery increases the quantity of oil recovered beyond that normally obtained through natural forces or drives within a reservoir. The oldest assisted recovery technique, waterflooding or water injection (often called secondary recovery) has been used for more than 100 years to maintain or increase reservoir pressure as the oil is withdrawn. By replacing part of the withdrawn oil, water injection can lower subsidence rates of the land above the reservoir; occasionally, as in Southern California, it is injected for this reason. Eventually the injected water makes up such a large fraction of the produced fluid, four to five barrels of water per barrel of oil, that the technique becomes unprofitable.[13]

In a waterflood, the lack of miscibility produces a sharp boundary or interface between the oil and the water phases; this fact and the different viscosities for the two fluids often lead to a channeling of the driving water through the oil or around it with concomitant loss of sweep efficiency for the driving fluid. The various miscible methods replace the sharp fluid boundary by a zone where the oil and drive fluid mix; this causes better cleanout of the volume swept. The fluid miscible with oil can be followed by a driving fluid with a mobility adjusted to maximize the volume swept by the miscible fluid.

Other assisted recovery techniques (often called tertiary recovery methods) can be applied to a field immediately after drilling, after primary recovery, or after waterflooding. Prior to the oil embargo, tertiary recovery in most fields was uneconomic. The current price of oil now makes the introduction of many enhanced recovery methods possible.

a. Hydrocarbon Miscible Methods

Hydrocarbon miscible methods are expected to account for about 5 percent of the oil derived from advanced recovery techniques.[14] In a hydrocarbon miscible project, a slug of liquid or gaseous hydrocarbons (usually intermediate weight hydrocarbons; for example, C_2 to C_6 molecules with a slug volume of about 5 percent of the pore volume of the reservoir) is driven through the reservoir by gas pressure. Usually natural gas or propane is used, but other gases are possible. The miscible slug lowers the viscosity of the oil and reduces capillary forces, thus helping the gas drive to force oil to the production wells. Some 20 projects of this kind are currently under way--mainly in Texas and California--with others planned. A number of companies are actively pursuing miscible hydrocarbon projects; among them are Mobil with seven projects and Amoco with four projects.[15]

b. Carbon Dioxide Miscible Methods

Some 8 percent of the advanced recovery is estimated to come from carbon dioxide (CO_2) miscible recovery methods.[13] At high pressures, carbon dioxide is miscible with oil and acts to lower the oil viscosity and aid production. Occasionally, an inexpensive local source of CO_2 allows use of a large slug and the CO_2 can then be followed by an immiscible water drive. Recently a high pressure valve failed in a CO_2 gas injection project in West Texas, and the released CO_2 resulted in the suffocation deaths of nine persons.[16,17] Eight CO_2 miscible projects are under way, including six in Texas. Amoco has three projects, Shell two projects, and Conoco two projects.[15]

c. Thermal Methods

About 30 percent of the future enhanced recovery is expected to come from thermal methods.[13] Thermal methods can greatly increase the production of very viscous oils since raising reservoir temperatures significantly lowers the oil viscosity. Hot water injection, one of the simplest thermal methods, has not yet been very successful. The more effective steam injection carries far more heat content due to its higher temperatures and especially due to its large heat of condensation. Steam flood techniques, first tried before the turn of the century in Pennsylvania, have only in the last decade had any significant success. Steam drive can be started almost immediately on a new field; it is almost never preceded by waterflooding.

A second major thermal method uses controlled slow underground burning of oil to provide the heat. A combustion front propagates through the reservoir by injection of oxygen and then air from behind. Only a small percentage of the oil burns as the front passes toward the producing wells. Those components that are the heaviest and most difficult to vaporize are combusted. These components are the most difficult to produce in any case. Waterflooding can follow combustion in a technique called COFCAW for Combination of Forward Combustion and Waterflooding.

Nearly 100 thermal recovery projects are currently underway. Nearly all are in California, although about 15 are in Texas. Mobil, Shell, Gulf, Getty, Exxon, Occidental, ARCO, and Standard Oil of California are among the major producers involved in these projects. About 20 more projects are planned, again mainly in California.[15]

d. Micellar Methods

Micellar methods are expected to produce 58 percent of future advanced recovery.[13] Water miscible techniques generally use water solutions for both the solvent slug and the driving fluid. The solvent or surfactant slug forms a micellar fluid (a microemulsion) with the contacted oil. Petroleum sulfonates are commonly used as the surfactant and the driving fluid is a dilute polymer solution (polysaccharide or polyacrylamide). Dilute caustic solution (NaOH) has also been used as the emulsifying agent with some success.

Substantial chemical requirements for micellar recovery will be encountered. From 7 to 15 pounds of surfactant (hydrocarbon sulfonates used as detergents and wetting agents) and from 4 to 10 pounds of co-surfactants (isopropyl alcohols) are required per barrel of oil produced. In addition, thickening agents for controlling the viscosity of the following waterflood are required: one to eight pounds of biopolymers or polyacrylamide, which is highly carcinogenic. For 500,000 barrels per day of production from micellar flood techniques, 1.2 billion to 2.5 billion pounds per year of surfactants, 180 million pounds per year of polymers, and 1 to 2 billion pounds per year of co-surfactants would be required.[18] Commercial productive capacity for these requirements does not exist today. Also, large volumes of water co-produced with the oil (four to ten barrels of water per barrel of oil) will either require treatment for disposal or reinjection into the formation.

Approximately 25 micellar flood projects are currently underway with another ten planned,[15] mainly in California, Texas, Oklahoma and Wyoming. A number of companies are involved in the projects, principally Mobil, Texaco, Marathon and Sun.

C. Technologies for Producing Pipeline Gas from Coal

The synthesis of high-Btu gas (primarily methane) from coal involves two basic steps: first, the gasification of coal by reaction with steam and oxygen to form a medium-Btu synthesis gas; and second, the catalytic reaction of the CO and H_2 in the synthesis gas (after suitable adjustment of the H_2/CO ratio) to form methane. Fifteen separate processes have been proposed, tested, or are in commercial operation to accomplish the first step of coal gasification. These processes differ in the temperature and pressure at which gasification takes place, the nature of the bed in which the gasification reactions occur, the method of feeding the coal, steam, and oxygen into the reactor, and so forth. A brief description of each process is given in Table II-1.

Beyond the gasification step the conversion of synthesis gas to methane follows basically the same steps for each process. These steps generally include: (1) quenching or scrubbing of the raw synthesis gas to remove tars and oil and/or particulates formed in the reactor, (2) CO shift, in which the H_2 to CO ratio is adjusted to 3:1 by reacting excess CO with steam to form H_2 and CO_2, (3) purification of the synthesis gas, involving primarily removal of the acid gases CO_2 and H_2S, (4) catalytic methanation to form the 900 to 1000 Btu-per-SCF product gas, and (5) removal of water vapor from the product gas and compression of the gas to pipeline pressure. These steps are illustrated in Figure II-4.

Numerous plans for utilizing coal to produce SNG have been announced by a number of pipeline companies. The plants closest to the construction stage are those planned by El Paso Natural Gas and WESCO (Western Gasification Company) for the Four Corners area of New Mexico. These plants are based on the Lurgi gasification process and will produce approximately 288 million- and 250-million-SCF per day, respectively, of pipeline quality gas.

First generation plants plan to utilize the Lurgi process because it is commercially available and its use has been reliably demonstrated over a period of many years. Because of certain drawbacks in the operation of Lurgi gasifiers, as discussed in the section on low-Btu gasification, second or third generation gasification plants will

Table II-1

SUMMARY OF COAL GASIFICATION PROCESSES

Gasifier	Description	Developer	Status
Atgas	Atmospheric, high temperature; crushed coal is injected into molten iron bath which provides heat for gasification, lime slag removes sulfur.	Applied Technology Corporation	Laboratory tests have been carried out.
Bi-gas	High temperature, pressurized, entrained bed; two stages--one for devolatilization, one for char gasification.	Bituminous Coal Research, Inc.	120 ton/day pilot plant under construction.
CO_2 Acceptor	Heat for gasification is provided by the reaction of CO_2 with dolomite; pressurized oxygen-free system.	Consolidation Coal Company	40 ton/day pilot plant is being operated.
Hydrane	Hydrogasifier, high direct methane yield due to hydrogenation of char to make CH_4 followed by hydrogenation of coal.	Bureau of Mines	10 lb/hr laboratory operation.
Hygas	Pressurized hydrogasifier, fluidized bed (see text).	Institute of Gas Technology	75 ton/day pilot plant operating.
In Situ	Coal is gasified in place, underground, through controlled injection of steam and oxygen (or air).	Bureau of Mines; Lawrence Livermore Laboratory	Some tests using air have been made; others to begin in 1975.
Koppers-Totzek	Atmospheric pressure, high temperature, entrained bed (see text).	Heinrich Koppers G.m.b.h.	Commercial
Lurgi	Pressurized, fixed bed (see text).	Lurgi Mineralstechnik G.m.b.h.	Commercial
Molten Salt	Molten sodium carbonate is used to catalyze synthesis gas production; pressurized.	M. W. Kellogg Company	120 ton/day pilot plant is being built.
Synthane	Pressurized, fluidized bed (see text).	Bureau of Mines	0.5 ton/day pilot plant tests completed; 70 ton/day plant under construction.
U-Gas	Pressurized; fluidized bed--low-BTU gas only.	Institute of Gas Technology	Gasifier to fuel a 100 MW power plant is being designed.
Union Carbide	Hot coal-ash recirculation provides heat for reaction of steam with coal; fluidized bed; pressurized.	Chemical Construction Corp.	25 ton/day pilot plant is under construction.
Wellman-Galusha	Atmospheric pressure; fixed bed.	Wellman Engineering Co.	Commercial
Westinghouse	Pressurized; fluidized bed; limestone in bed absorbs H_2S; external char combustion provides heat; low BTU gas only.	Westinghouse Research Labs	14 ton/day pilot plant is being built.
Winkler	Atmospheric pressure; fluidized bed; coal is introduced via variable-speed screw feeder.	Davy Powergas, Inc.	Commercial

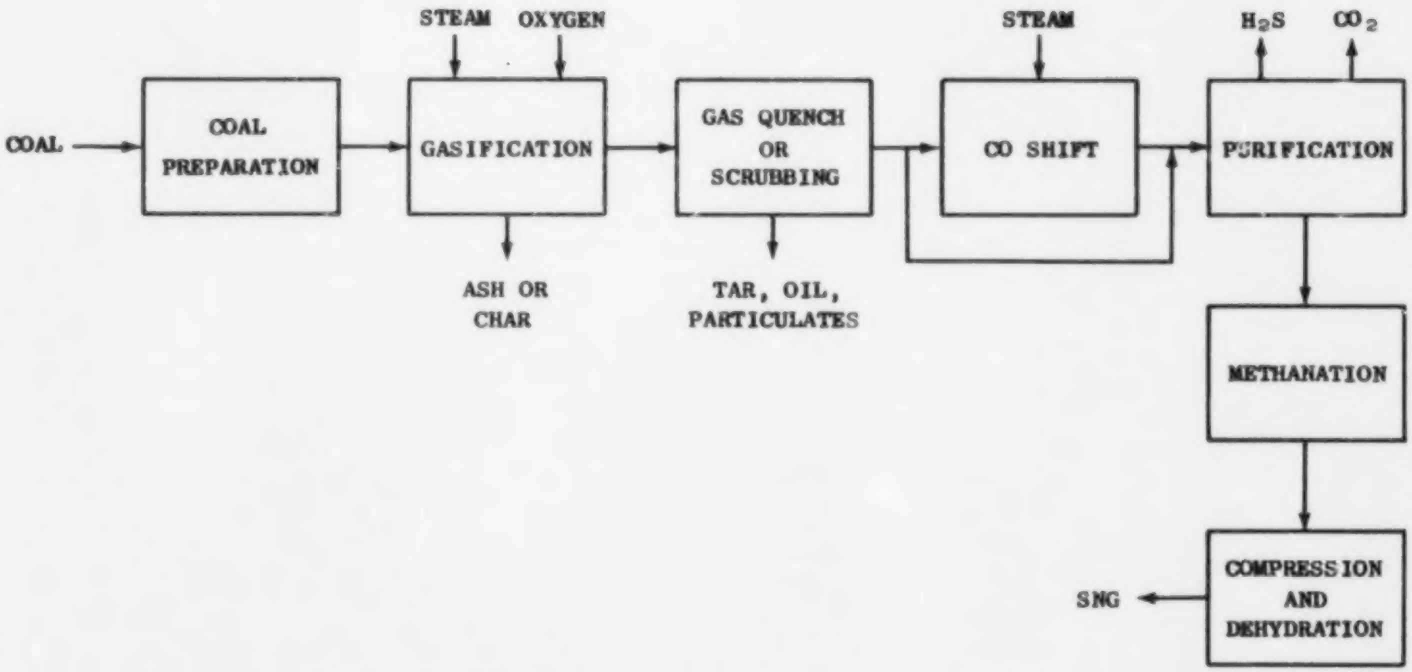
STEAM
OXYGEN
STEAM
H_2S
CO_2
COAL
COAL PREPARATION
GASIFICATION
GAS QUENCH OR SCRUBBING
CO SHIFT
PURIFICATION
ASH OR CHAR
TAR, OIL, PARTICULATES
METHANATION
SNG
COMPRESSION AND DEHYDRATION

FIGURE II-4. FLOW DIAGRAM FOR THE PRODUCTION OF SYNTHETIC NATURAL GAS FROM COAL

undoubtedly use more advanced processes such as the Bureau of Mines Synthane process, or the Institute of Gas Technology (IGT) Hygas process, as these technologies become available for commercial application.

The operation of the Lurgi gasifier has been discussed previously in Section A. The major difference between producing synthesis gas for use in methane production and producing low-Btu fuel gas is that oxygen must be used in place of air as the oxidizing medium in gasification. If air were used, an unacceptably high level of dilution by nitrogen would be introduced into the synthesis gas, and ultimately into the high-Btu product gas.

One of the more promising new processes for coal gasification is the Synthane process developed by the U.S. Bureau of Mines.[10] The Synthane process is similar to the Lurgi process, except that a fluidized bed is used in the reactor instead of a fixed bed. The turbulent motion induced in the fluidized bed allows greater exposure of the coal surface to the gasifying medium so that shorter residence times are required in the reactor and a greater throughput of coal can be achieved as well as a more efficient utilization of carbon. Furthermore, caking bituminous coals can be readily handled, although some pretreatment is required. In the first stage of the Synthane process, crushed and dried coal is partially reacted with steam and oxygen at 800°F. In this way, highly volatile components are removed from the coal and its caking tendency is destroyed. The devolatilized coal is fed into the main fluidized-bed gasifier where it is reacted with steam and oxygen at 600-1000 psi and 1800°F. A direct methane yield of about 15 percent is achieved (compared to less than 5 percent for Lurgi), thus reducing the amount of methanation required to produce SNG. By carefully controlling the combustion of coal, a considerable quantity of char (containing about 30 percent of original carbon in the coal) is obtained as a byproduct which can be burned to provide steam and electricity to run the plant. Subsequent to gasification, the synthesis gas is quenched to remove tars and oil and passed through cyclones to remove particulate matter before entering the final stages of SNG production. Bench-scale tests of the Synthane process have been completed and a 70 ton-per-day pilot plant has been built for the Bureau of Mines at Bruceton, Pennsylvania.

Another process which appears to be very promising for the production of high-Btu gas from coal is the Hygas process developed by IGT.[3] This method of coal gasification is different from the Lurgi and Synthane in that a hydrogen-rich gas rather than steam is used as the gasifying medium. The predominant reaction is of carbon with hydrogen to yield methane; thus, a high direct yield of methane is achieved. The first step of the process is to devolatilize the crushed coal with hot air and steam, after which it is slurried with light oil and fed to the top of the reactor. At the bottom of the reactor, gas consisting of H_2, CO, and steam is introduced into the fluidized bed. This gas is produced by reacting a mixture of steam and oxygen with byproduct char. (Other methods of producing H_2-rich gas have been tried, but the steam-oxygen process appears to be the most feasible.[9]) In the reactor, three temperature zones of approximately 1000°F, 1200°F, and 1750°F are formed. In the first zone, the light oil is vaporized, and hydrogasification takes place in the remaining two zones. As in the Lurgi and Synthane processes, the raw synthesis gas must be quenched to remove product oil and any remaining slurry oil. A 75 ton-per-day gasifier based on the Hygas process is being operated by IGT in Chicago. Successful runs of up to 100 hours duration have been achieved.

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III. SOCIAL IMPACTS OF ENERGY DEVELOPMENT IN A RURAL AREA: A CASE EXAMPLE OF WESTERN COAL DEVELOPMENT

A. Introduction

Throughout the report we have referred to the potentially serious adverse impacts of a rapid rate of energy development in a predominately wilderness or rural area. We have particularly stressed the possibility of this phenomenon occurring if a high growth of energy-related activities occurs in the western states of the United States or Alaska. The purpose of this section is to illustrate the possible nature of these impacts by projecting approximate population influxes due to energy development in the West, by discussing some of the attitudes of the present population in the West, and by reviewing the impacts which have already occurred in western towns that have been subject to extremely rapid growth rates in the recent past. The case example chosen pertains to the four options for western energy development analyzed in volume two of this report.

B. Overview

The potential for significant, rapid, and potentially irreversible alteration of the way of life and human environment of the western coal regions is high, given the rapid expansion of western coal mining activity, the great pressure to build energy conversion facilities near the mine, and the lack of advance preparation to cope with the problems inherent to such rapid development. One example might serve to illustrate the changes projected to occur in the West. From 1969 to 1973, production of coal in Montana increased from 1 million to 16 million tons, or from

0.2 percent to over 3 percent of the nation's coal supply. Standard projections for 1980, just five years hence, place Montana coal production at between 75 and 80 million tons.[1]

The population influx into a region relative to the prior population of the region is one measure of social impact. The increase in population associated with coal development in the West is highly dependent on the nature and location of the coal use. This is illustrated in Table III-1 for four options for using western coal.

Table III-1

ESTIMATED PERMANENT POPULATION INCREASE IN THE WEST DUE TO ENERGY DEVELOPMENT

Options	Estimated Permanent Population Increase in the West per 10^{15} Btu Electrical Output per Year*
Direct electricity generation on-site; transmission to the Midwest	55,000-85,000†
Low-Btu gasification on-site; combined cycle electricity generation; transmission to Midwest	100,000-180,000
Coal transport to Midwest by rail; direct electricity generation	20,000-40,000
Coal transport to Midwest by rail; low-Btu gasification; combined cycle electricity generation	20,000-40,000

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*Based on information contained in Tables III-2 and III-3.

†During peak construction years, approximately equal population increase associated with temporary construction workers can be expected.

Table III-2

DIRECT EMPLOYMENT FOR ENERGY EXTRACTION AND CONVERSION

	Per Standard Size Plant or Operation[†]	Per 10^{15} Btu Equivalent Electrical Output
Mining	60-120 permanent 60 construction	3000-6000 permanent
Electricity generation		
• direct burning	100-150 permanent 2500 construction	4800-7200 permanent
• low-Btu gasification/ combined-cycle power generation	240-420 permanent 2500 construction	11,000-20,000 permanent

Table III-3

POPULATION INCREASE FOR ENERGY EXTRACTION AND CONVERSION[‡]

	Per Standard Size Plant or Operation[†]	Per 10^{15} Btu Equivalent Electrical Output
Mining	400-800	20,000-40,000
Electricity generation		
• direct burning	700-1000	30,000-50,000
• low-Btu gasification/ combined-cycle power generation	1700-3000	80,000-140,000

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[*] Data taken from References 3 and 9.

[†] Assumed standard size for the operations: 3 million tons/year for mining and 1000 MW(e) for both direct burning and low-Btu gasification to generate electricity.

[‡] We have aggregated data from Montana, Wyoming, and North Dakota to average factors for family size and indirect employment. From the Northern Great Plains Resources Program analysis, we calculate an average family size of 2.3 and an average factor for induced employment of 2.2 for each person employed by energy industry. We have not included construction workers. The average population multiplier so calculated (1+2.2) x 2.3 equals 7.

In order to put these population increases into perspective, we note that

- These increases are added to a base level of approximately 400,000 people presently residing in the coal-bearing regions of Montana, Wyoming, and North Dakota, where most of the coal development is expected.
- Typical projections anticipate 200 million tons of coal produced per year in the West by 1985 and 400 million tons per year by 2000.[2] This is equivalent to 3.6×10^{15} and 7.2×10^{15} Btu resource energy, respectively, and about one-third of these values when converted to electricity.

Thus, it is apparent that population increases in the coal-bearing regions of the West could be large and rapid in the next decades, relative to present population levels in the region. We now analyze specific impacts of these levels and intensities of population growth.

C. Impact on Towns

Most of the towns in the impact area have fewer than 5000 inhabitants at present. The towns of Forsyth and Colstrip in Montana and Gillette, Wyoming, with populations of 2700, 1800, and 7800, respectively, are worthy of special note since extensive energy development plans are proposed or underway near these locations.[4] Two 350-MW power plants are now under construction at Colstrip. Two additional 660-MW power plants have been proposed for the site; construction of these facilities awaits the decision of the state of Montana as required by the 1973 Utility Siting Act of Montana.[5] If the decision is in the affirmative and construction takes place, Colstrip will have a generating capacity in the late 1970s comparable to that of the Four Corners area now.* Forsyth will be directly impacted by virtue of its proximity to Colstrip. Gillette, a town affected by an oil boom in the 1960s, is located in a coal-rich area highly susceptible to development. For Gillette, as for many other towns in the West, it is difficult to anticipate the timing and location of future growth. This is because of great uncertainty as to which coal fields will prove most economically attractive.

1. The Problems of a Town in Rapid Growth

A town in rapid growth is subjected to problems related to housing, health care, crime, education, and less tangible ones, such as loss of community spirit.

Two of the few towns in the West undergoing rapid expansion that have been studied for social impact of a sudden population increase are Rock Springs, Wyoming, located near the Jim Bridger coal mine and power plant, and Gillette, located within the vast Powder River Basin coal deposits.[7]† Data on these towns[7] and information on other boom towns[8] illustrate the effects of rapid development.

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*In January 1975, the Department of Natural Resources of Montana recommended against the construction of these proposed facilities with the statement "The Department is not persuaded that there is a basis of the need for a 1400 MW facility in Montana,...[or]...that reasonable alternatives to the proposal do not exist,...[or]...that the proposed facilities represent the minimum adverse environmental impacts for the state of Montana,...[or]... that the obligation of Montana to the rest of the nation or the Pacific Northwest necessarily goes beyond making energy available through reasonable alternatives,...[or]...that the proposed facilities will serve the public interest, convenience and necessity."[6]

†A serious limitation of the data of Reference 7 is that they were gathered during the period of boom and cannot be compared with the prior condition of the town; they are, however, compared with information from similar communities nearby, when possible.

a. Housing

The population of Gillette grew from 3600 in 1960 to 8000 in 1968, dropped to 7200 in 1971 and has subsequently increased to 9000.[7] Rock Springs has grown even more rapidly: from 12,000 in 1970 to more than 26,000 in 1974. Similarly, Sweetwater County, in which Rock Springs is located, grew from 18,000 to 45,000 between 1970 and 1974. The result is that new housing often consists primarily of trailers for all except higher echelon managers.* Motel rooms, boarding rooms, and even tents provide shelter on a semipermanent basis for workers who can find no alternative.

b. Health Services and Related Problems

In the time that Rock Springs increased in population by one-third, demand for emergency room service in the hospital increased by 400 percent;[7] emergency room services commonly involve a wait of three hours. Mental health care is limited and badly needed: Sweetwater County, in which Rock Springs is located, apparently suffers a very high rate of attempted suicide.[9]

For Campbell County, in which Gillette is located, the ratio of marriages to divorces is 1.8 compared with about 3 for neighboring counties. The frequency of arrests and public drunkedness is two to four times greater in Campbell County than in neighboring counties. In 1970, in a population of under 13,000, there were over 1000 arrests.[7]

c. Education and Other Public Services

The drop-out rate in the Campbell County High School is higher than that of neighboring counties. Because the ratio of school children to the total population may increase from about one in seven to one in three during boom times, school system accommodations are heavily stressed.

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* A typical city during the boom might have as much as 35 percent of the population living in mobile homes and trailers.[8]

2. Barriers to the Solution of Social Problems in Boom Towns in the West

The information presented above and data on other social impacts, such as labor difficulties (extremely high turnover of workers), resource demands, recreation, land use problems, etc., support the general conclusion that Rock Springs and towns like it find it very difficult to cope adequately with problems of development. This inability is likely to be a widespread phenomenon. Only a few towns in the coal regions have a city planner and most do not have city councils or other governmental structures equipped with the knowledge or the expertise to plan for future rapid development.[4] Even if the capability for planning existed, the planning problem is exacerbated by the fact that the town officials do not generally know in advance the degree to which they will be affected, because of uncertainty in the plans of the energy companies. Perhaps the factor that most complicates planning efforts is that new residents often differ in lifestyle and outlook from the present population in the region. A primary characteristic of the new settlers is that they often view themselves as drifters and temporary employees, with the result that they perceive little stake in the results of their activity and that of others who have moved to the area.[4] Such a divergence of goals among the new and old populations has typically led to an environment of such tension that the solving of problems such as the need for new public facilities through bond issues is made very difficult.

Obtaining adequate financing for new services is also difficult for boom towns. Often the coal mines and energy conversion facilities lie in tax districts other than that in which the employees live. One example of this is Big Horn County, Montana, where 70 percent of the employees of energy firms are expected to live but which expects to receive little or no tax benefits from coal development.[10] A disparity in timing of tax revenues also exists: new tax dollars generally come three or more years after the largest population influx and its impacts have occurred. The problems of proper and timely allocation of tax revenues may be capable of administrative solution but, to the best of our knowledge, they have not been addressed in a substantial manner in any of the western coal states.

We conclude that the phenomenon of Rock Springs and other cities already affected by the still modest growth of coal-related activities is likely to be widespread in many towns of the West, if projections of growth associated with energy development are realized.

D. Effect on Ranchers

Much of the population in the western coal-bearing regions live on and from the land. Although the aridity of the region is not conducive to intensive agricultural and ranching enterprises, nonetheless most of the available land is devoted to these activities. The human environment of these regions is in large measure determined by the lifestyle and attitudes of the ranchers who make it up. One study indicated that the "...majority of ranchers in southeastern Montana interviewed to date are against all-out coal and energy development and would...like to see the coal people go away forever."[4] This statement should not be interpreted as indicating opposition by all of the ranchers in the region; many have sold subsurface rights to coal lying under their land and are prepared to face the consequences of their decision.

Some of the major concerns of the rancher when confronted with the prospect of extensive coal development are likely to be:

- Loss of water rights or drying up of sources of water.
- Impairment of needed rights of way and other facilities of the region necessary to support ranching activities.

- Threat of condemnation of the land by energy companies.
- Loss of political and social preeminence in the region; appearance of the ranchers as a reactionary force in the face of progress.
- Significant lifestyle changes throughout the coal-bearing area.

It is thus not surprising that "very few persons believe that coal development and ranching can go on side by side."[4] If this belief proves correct, the impact of development in the next few decades will be no less than a fundamental change of the nature and environment of the western coal-bearing regions in Montana, North Dakota, and Wyoming.

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IV. WATER AVAILABILITY AND CONSUMPTION FOR ENERGY DEVELOPMENT IN THE COLORADO AND MISSOURI BASINS

A. Introduction

Processing oil shale in the Colorado Basin and western coal in the Missouri Basin will require large amounts of water. These Basins and the river system that provides their water supplies are shown in Figure IV-1. Two recent studies, one for each Basin, which examine the impact of these water requirements on the projected water availability and utilization for these regions, have been completed by two Department of Interior Task Forces. These studies together with other more detailed studies of the energy conversion processes involved are used here to address the questions:

- To what extent will allocation of water resources to a major energy development program involving oil production from oil shale, and electricity production from direct burning and low-Btu gasification of western coal impact other nonenergy applications?
- To what extent will allocation of water resources to future energy and nonenergy uses endanger instream flows in the Basins?

Although these questions cannot be answered definitely on the basis of currently available data on water availability, an indication of the degree of the potential problem has been obtained.

B. Summary and Conclusions

Key findings are:

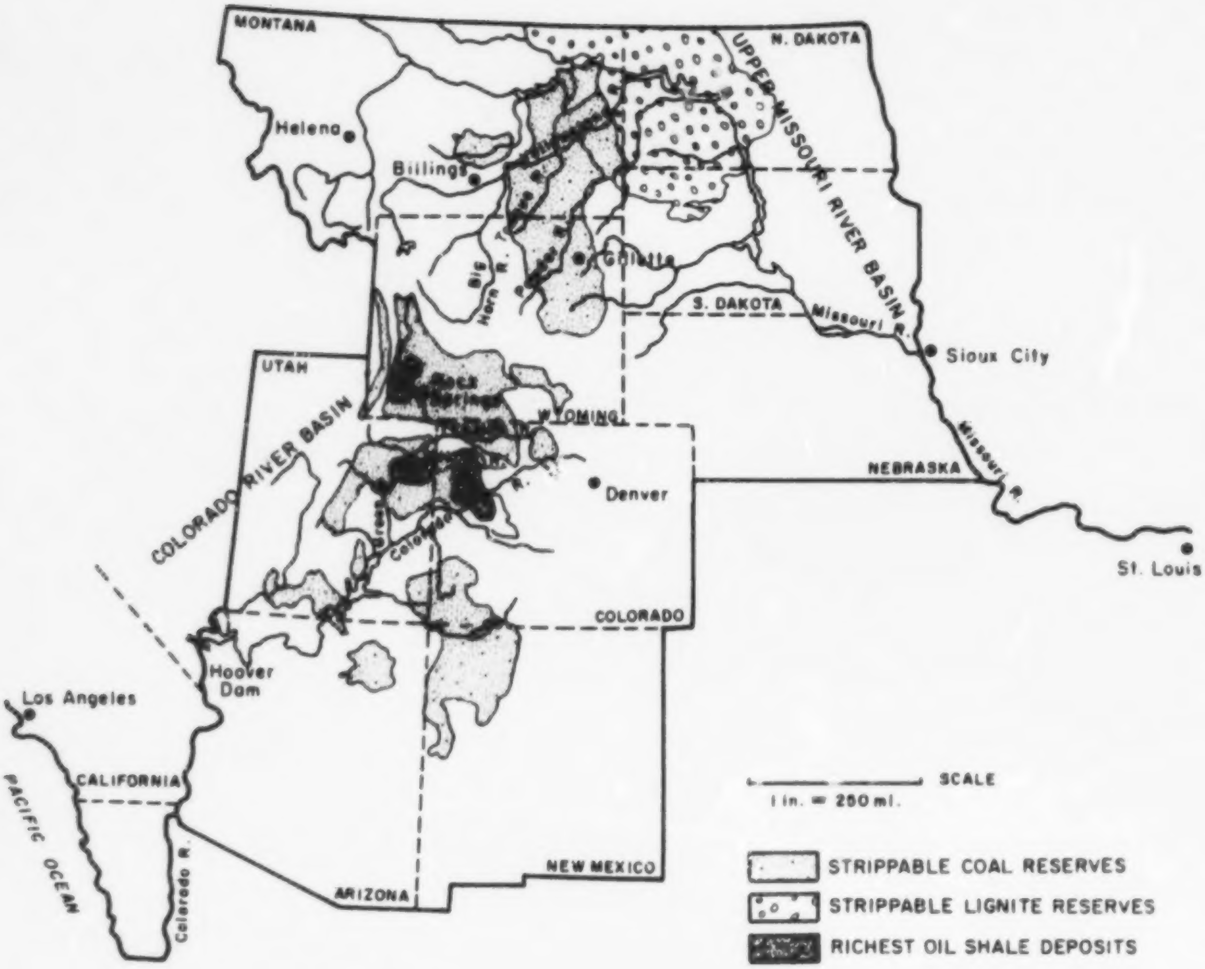
MONTANA
N. DAKOTA
UPPER MISSOURI RIVER BASIN
Helena
Billings
Big Horn R.
Gillette
S. DAKOTA
Missouri R.
Sioux City
UTAH
Rock Springs
WYOMING
COLORADO RIVER BASIN
Denver
NEBRASKA
Missouri R.
St. Louis
Green R.
Colorado R.
COLORADO
Hoover Dam
Los Angeles
CALIFORNIA
PACIFIC OCEAN
Colorado R.
ARIZONA
NEW MEXICO
SCALE
1 in. = 250 mi.
STRIPPABLE COAL RESERVES
STRIPPABLE LIGNITE RESERVES
RICHEST OIL SHALE DEPOSITS

FIGURE IV-1. COLORADO AND MISSOURI RIVER BASINS

- The onsite water requirements for the three options that process minerals in the West are shown in Table IV-1.

Table IV-1

WATER CONSUMPTION OF ENERGY TECHNOLOGIES*

Options	Thousand acre-feet/year for 10^{15} Btu output	
	Wet Cooling	Dry Cooling
Oil from oil shale	90	70
Electricity from burning western coal	750-900	160
Electricity from low-Btu gasification of western coal/combined cycle operation	~1000	~500

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[*] There is a conceptual problem in comparing the inputs or outputs of one form of energy production with those of another, as discussed in section I. In Table IV-1, water requirements to produce 10^{15} Btu of crude oil from oil shale are compared with those to produce 10^{15} Btu of electricity. The end uses and end use efficiencies of crude oil and electricity are generally not comparable. It might be useful to think of the crude oil as input into a power plant, in which case the water consumption numbers for oil shale given in Table IV-1 should be multiplied by 3 if they are to be compared with electricity generation.

- There is evidence that degradation of the natural environment due to reduction of instream flows in both basins as well as a shortening of the annual navigable period of the upper Missouri River will occur if utilization approaches the maximum potentially available.
- The estimates of the maximum potentially available surface water for annual allocation to all uses, the present level of use, and the remaining surface water resources in each of the two major locations of oil shale and coal in the West are shown in Table IV-2.

Table IV-2

WATER AVAILABILITY IN THE UPPER COLORADO AND MISSOURI RIVER BASINS

		Water in Million Acre-Feet per Year			
Basin	Primary Source of	Maximum Available	Available with Adequate Environmental Protection	Present Use	Remainder
Upper Colorado River	Oil shale	5.8	unknown	3.7 (1974)	≤2.1
Upper Missouri River	Western coal	10.0	5.8	2.8 (1970)	3.0-7.2*

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*Lower estimate refers to remaining surface water allowing adequate protection of instream values; higher estimate is of total surface water availability.

- While there is presently an overappropriation of water rights in both basins, reallocation of water rights can be effected through purchase, abandonment, or altered use that make possible allocation of portions of the water resources for future energy development.
- Projected nonenergy water utilization for the year 2000, most of which is agricultural, with the remainder left for energy development is shown in Table IV-3.

Table IV-3

PROJECTED WATER AVAILABILITY IN THE WEST IN THE YEAR 2000

		Water Available for Energy Development in million acre-feet per year (Year 2000)	
Basin	Nonenergy Water Utilization in million acre-feet per year (Year 2000)	With Protection of Instream Flows	Without Protection of Instream Flows
Upper Colorado River[7]	5.1	0	0.7
Upper Missouri River[8]	6.0	0	4.0

The conclusions are:

- **If instream flow levels are to be protected, the anticipated growth of nonenergy uses of water will consume all that is available before the year 2000, unless large amounts of water are imported.**
- **If instream flow requirements are not fully protected or are much less than has been estimated, adequate water could be made available in the Colorado River Basin for a significant oil shale industry and in the Missouri River Basin for western coal conversion industry at least to the year 2000.**
- **In either case, a high level of energy development will preclude the allocation of water resources to nonenergy uses at an early date (probably within the next decade) if adequate environmental protection is to be afforded to stream flows, or at a later date if environmental values are not protected (in the absence of large water imports into the region).**
- Further investigation of instream flow requirements in the Colorado and Missouri River Basins is needed to allow a more reliable assessment of the compatibility between energy development and maintenance of the riverine ecology.

C. Water Requirements per 10^{15} Btu Useful Energy Output

The water requirements for the three energy-producing operations discussed in this report which use western coal and oil shale are shown in Table IV-4.

1. Oil Shale

The requirements for water in surface and underground mining and processing of oil shale for 10^{15} Btu oil production per year (500,000 bbl per day) are shown in Table IV-5.

Dry cooling of the power plant instead of water cooling can reduce the water requirements for cooling to zero. Recognition of the limitations of the available water supply may put pressure on developers to use that method since overall water requirements are reduced by 25 percent

Table IV-4

WATER CONSUMPTION OF ENERGY TECHNOLOGIES*

Process	Thousand Acre-feet/year for 10^{15} Btu output† Wet Cooling	Thousand Acre-feet/year for 10^{15} Btu output† Dry Cooling	Number of Standard Size Plants
Oil from oil shale	90	70	5 one hundred thousand bbl/day plants
Electricity from burning western coal	750-900	160	45 one thousand MW(e) plants at 75 percent load factor
Electricity from low-Btu gasification of western coal/combined cycle operation	~1000	~500	45 one thousand MW(e) plants at 75 percent load factor

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[*] See footnote, page IX-3.

[†] We have generally specified a range for the consumptive use of water reported above. When a single figure is given, as for oil shale, the uncertainty is generally of the order of plus and minus 15 percent, for present technology. The uncertainty in the estimate for low-Btu gasification using wet cooling is greater, approximately 25 percent.

Table IV-5

WATER REQUIREMENTS FOR CRUDE OIL PRODUCTION FROM OIL SHALE

Process	Acre-feet/year per 10^{15} Btu output
Mining and crushing	4,500
Retorting	6,500
Shale oil upgrading	18,000
Processed shale disposal	36,000*
Power requirements	4,000-22,000†
Other nonplant uses	1,500
Total	70,000-88,000

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[*] Used to wet shale with 20 percent water by weight of shale. If a slurry of water were used to transport the spent shale to the disposal area, 50 percent water by weight would be required, multiplying this requirement by 2.5. Slurry methods are unlikely to be used for this reason.

[†] 850 megawatts generated or 1300 megawatts installed capacity. The upper estimate is for wet cooling; the lower, for dry cooling.

with dry cooling compared with full evaporative water cooling.

2. Electricity from Direct Burning of Western Coal

Wet cooling towers are the most commonly used method to dissipate the large quantities of waste heat resulting from electricity generation. Wet cooling involves transferring heat from the turbine exhaust steam to water, which is circulated through the cooling tower. The water requirements of wet cooling, 12,000 to 17,000 acre-feet per year for a 1000 MW(e) plant operating at a 75 percent load factor, are to replace the water lost in evaporation.[2] Nonplant water uses such as evaporation in surge ponds, percolation, dust control, and urban use consume about 3000 acre-feet per year for a 1000 MW(e) plant. For an output of 10^{15} Btu electricity per year, the total water consumption is therefore between 750,000 and 900,000 acre-feet per year.

The two common alternatives to wet cooling are once-through cooling systems and dry cooling towers. The once-through cooling process draws water from some natural body of water into the plant, transfers waste heat to the water, and returns the water to the original source. Although recent regulations regarding thermal discharges to bodies of water are no longer as restrictive as prior rules, which tended to rule out the use of once-through cooling, this process is nonetheless very unlikely to find widespread use.[3] This is especially true for the West, where the high cost of water tends to preclude once-through cooling.

Dry cooling towers effect a transfer of the waste heat from the turbine exhaust steam to water circulating in a closed system to air in a manner similar to that of an automobile radiator system. Water consumption is thus restricted to a negligible amount of leakage from the dry cooling system and the non-plant water uses. This corresponds to 160,000 acre-feet for 10^{15} Btu electrical output. The major disadvantage of dry cooling is that it increases the cost of electricity, both by increasing capital costs and by reducing the efficiency of the power plant operation. The increased cost of electricity when dry cooling is used is estimated to be approximately 20 percent, divided almost equally between higher fuel costs (due to the diminished efficiency of the plant) and higher capital costs.[4*]

3. Low-Btu Gasification of Western Coal/ Combined Cycle Power

The major requirements for water occur in the gasifying process where water is a source of hydrogen, and in both the gasification and power generation processes to dissipate waste heat. Since no direct and reliable estimates of the water requirements for low-Btu coal gasification/ combined cycle power generation are available, we have estimated the water consumption on the basis of similar technologies. For both high-Btu gasification and coal liquefaction, water consumption is approximately 130,000 acre-feet per 10^{15} Btu output.[5,6] As noted, electricity generation consumes about 825,000 acre-feet (wet cooling) or 160,000 acre-feet (dry cooling) per 10^{15} Btu output. Assuming 40 percent efficiency for combined cycle part of the process, we estimate water requirements to be 1.2 million acre-feet per year if wet cooling is used and 500,000 acre-feet per year for the dry cooling option. These estimates may be somewhat high since the cooling requirements of low-Btu gasification are less than those for the two comparison processes.

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[*] The estimate reported in Reference 4 assumed a discount rate of 8 percent on capital costs. The higher current interest rate tends to increase the cost of dry cooling relative to wet cooling. However, the increased capital cost of electrical generating facilities reduces the percentage increment in cost associated with dry cooling. As such, the 20 percent increase in electricity cost is still a good approximation.

D. Water Availability for Energy Use in the Colorado Basin

1. Water Resources

a. Surface Water

The most widely quoted estimate for the maximum availability of surface water for consumption in the upper Colorado River Basin is 5.8 million acre-feet per year.[7] This figure includes the following assumptions:

- 8.5 million acre-feet released annually to the lower Basin (Arizona, New Mexico, Mexico) in accordance with the appropriate treaties, compacts, and agreements.
- Twenty-six million acre-feet of active storage in the upper Basin to meet commitments to the lower Basin through the most critical low-flow periods of record (1931-34)
- Allowances for shortages to irrigation users during subnormal years.

This estimate is based upon an average of 14.952 million acre-feet per year virgin runoff in the Colorado River at Lee's Ferry (on the border between the upper and lower Basins). This runoff has varied from 6 to 24 million acre-feet per year. Thus, in the worst drought year encountered to date, 2.5 million acre-feet from the 26 million acre-feet of storage would be required from the upper Basin storage to maintain downstream flow commitments.

The effect that full use of 5.8 million acre-feet/year would have on instream flows thoughout the basin has not been assessed. A study of comparable depletion in the Missouri River Basin found that 60 percent of the estimated maximum availability can be considered a threshold for degradation of biologic values resulting from reduction of instream flows.[6] Thus, an estimate of available water consistent with maintaining adequate instream flows may be significantly lower than 5.8 million acre-feet per year.

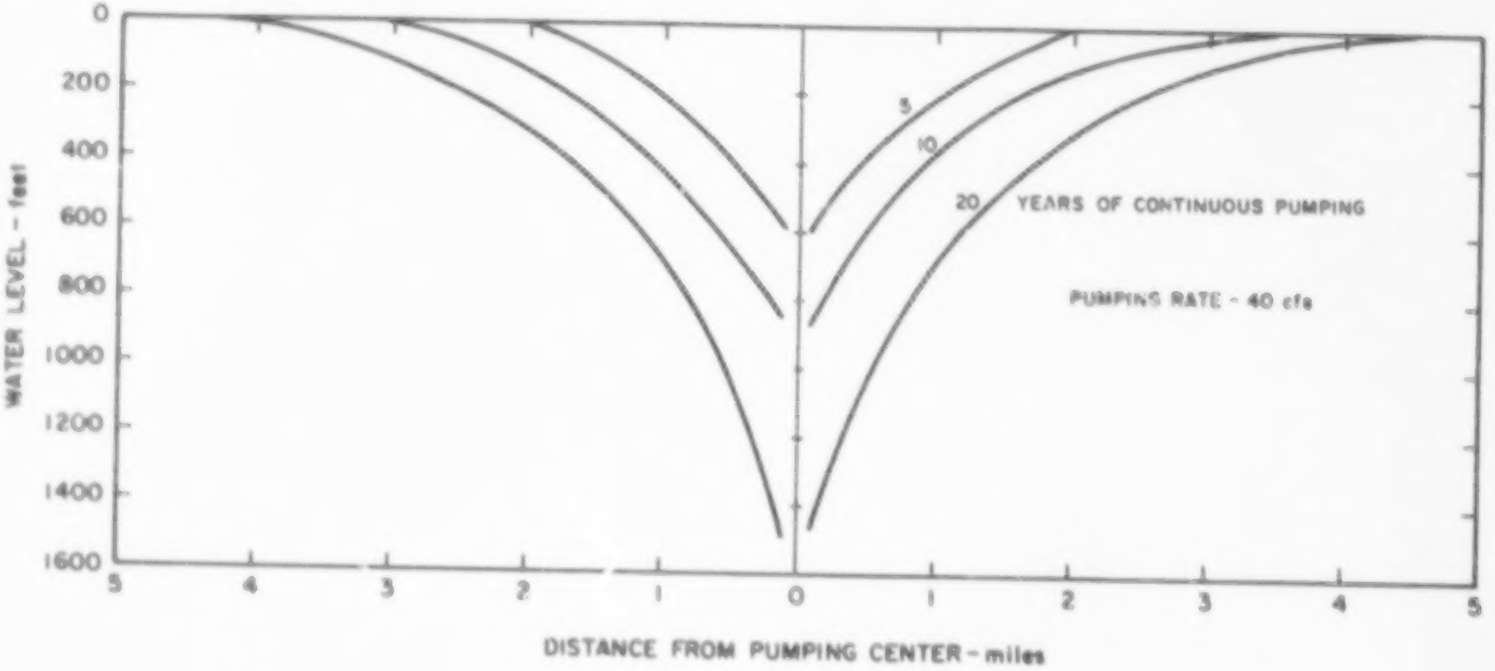
b. Underground Water

A shorter term and supplemental source is ground water. There is an estimated 50 to 115 million acre-feet stored in the upper 100 feet of saturated geohydrologic units. However, the portion of this water that is replenished each year due to streams, evaporation, wells and subsurface movement out of the region is estimated at 4 million acre-feet. More directly applicable to energy uses are the deep aquifers--the Green River and Uinta Formations. These are estimated to hold 25 million acre-feet.[1]

The recharge rate for these underground water sources can be illustrated by the rate of lowering of the water table near a discharge point such as a mine site at which ground water is pumped for use. Figure IV-2 shows the effect on the water table of pumping a maximum rate of 40 cfs (29,000 acre-feet per year). This lowering of the water table would result in the shallower wells becoming nonproductive, the reduction of volume in large streams, and the drying up of smaller streams in an area of up to a few miles around the site. While some oil shale projects have proposed using ground water obtained during mine dewatering during the first five to ten years as their primary source of water, it is recognized that in the longer term, ground wells would have to go very deep to maintain an adequate supply of water and the dry area around the well would eventually become unacceptably large. Thus, surface sources must be relied on for the major portion of oil shale and other energy processing requirements.

2. Colorado Basin Water Rights[7]

Colorado has two types of water rights, which are granted through the courts: absolute and conditional. Absolute rights are granted only after a project is completed and otherwise prepared to use water. Conditional rights are appropriated during the planning stage to



SOURCE: Final Environmental Statement for the Prototype Oil Shale Leasing Program, 1973, Department of Interior

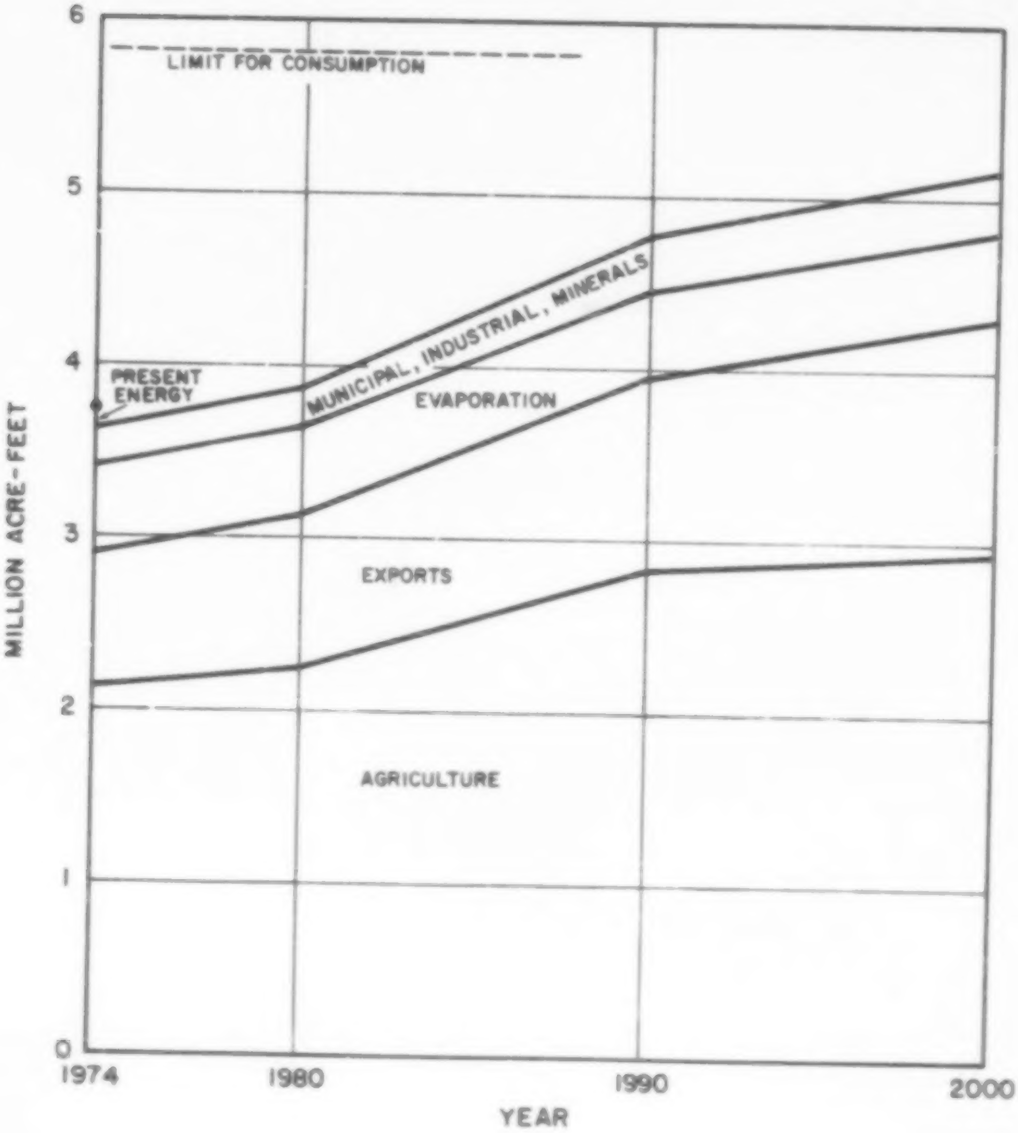
FIGURE IV-2. EFFECT OF GROUND WATER DEPLETION ON THE WATER TABLE

provide some assurance to the developers of the eventual availability of water. A system or priority is exercised in which junior, more recent, rights can be exercised if more senior rights are not using the full flow of the stream or have been abandoned. Since the court procedures generally grant new rights if properly applied for, unless they are opposed by adversary procedures, the result is that most streams in Colorado have been overappropriated with conditional and absolute decrees but still have available water which could be but is not presently used. More than 800,000 acre-feet per year of these conditional decrees belong to oil companies and another 275,000 acre-feet of rights have been filed by oil companies but not yet approved.[8] Additional flexibility and opportunity to obtain water rights is afforded by the relatively open market for their purchase and the fact that Colorado water rights are generally transferable apart from the land to which they were originally applied.

Thus, the fact that the available water of the Colorado Basin is presently overappropriated many times does not deny the opportunity for a sizable oil shale industry to obtain necessary water rights. The question of adequacy of available water must therefore be pursued by projecting probable future use against the estimate of available water.

3. Present and Projected Nonenergy Uses

Figure IX-3 shows the present utilization of water as well as projected future uses to the year 2000. The future agricultural uses, which consist primarily of irrigation projects, are expected to reach an added 800,000 acre-feet annually by year 2000. This estimate is based on irrigation projects currently planned or under construction. This amount, however, is subject to change through reallocation by means of purchase or other reassignment through normal state water rights processes. The future economics of irrigation will play a major role in determining the degree to which this large potential allocation is realized. The rest of the future projection shown is for exports and other uses, consisting



SOURCE: Adapted from "Report on Water for Energy in the Upper Colorado River Basin," U.S. Department of Interior, July 1974

FIGURE IV-3. PROJECTED WATER UTILIZATION FOR NONENERGY APPLICATIONS IN THE UPPER COLORADO RIVER BASIN

primarily of exports out of the basin for municipal purposes.

4. Projected Energy Uses

The projections of Figure IV-3 indicate that if the available limit for consumption is as high as 5.8 million acre-feet per year, up to one million acre-feet per year are available for energy development through 1990. Beyond that point, energy development is necessarily in competition with agricultural and other uses. If the growth rate of other uses decreases as projected between 1990 and 2000, energy development can consume up to 700,000 acre-feet per year up to the year 2000, after which competition for water resources will restrict growth of some uses.

If, on the other hand, significantly less than 5.8 million acre-feet/year are available for future growth, as is indicated by analogy with the instream flow study of the upper Missouri Basin, then consumption will become restricted much sooner. In either case, it is clear that although the nature of the tradeoffs between energy and other uses of water is complex, major new energy development in the Colorado Basin will at some point in the near future be in direct competition with further growth of agricultural and other uses, unless extensive aqueduct and dam construction projects are undertaken in order to import and store large quantities of water.

E. Water Availability for Energy Uses in the Missouri Basin

1. Water Resources

The Water Work Group of the Northern Great Plains Resource Program has estimated that 10 million acre-feet per year could be depleted from the upper Missouri Basin while maintaining a minimum flow throughout drought periods and also maintaining partial service to navigation.[6] This estimate is derived from an average annual flow of 21,821,000 acre-feet per year at Sioux City, Iowa, as of 1970.

Another estimate was developed by the Instream Needs Subgroup of that work group which assessed the streamflow rates necessary to avoid significant degradation of the "aquatic, biologic, benthic and aesthetic values of a stream and preserve the existing fishery." While this group recognized the elusiveness of the task of defining such requirements in a quantitative manner, they produced a recommended set of instream flow requirements which reduced the amount of water available in excess of then-current (1970) uses to somewhat in excess of 3 million acre-feet annually.[6]

Both of these estimates of future water use require new storage developments to support the diversions as well as the provision of aqueducts from points of the storage location to points of use.

The other potential source of water, ground water, has not been assessed to the degree that it has for the Colorado Basin. However, at best it would be a temporary source that would increasingly lower the water table in the surrounding region and thereby degrade the environment.

2. Water Rights in the Missouri Basin

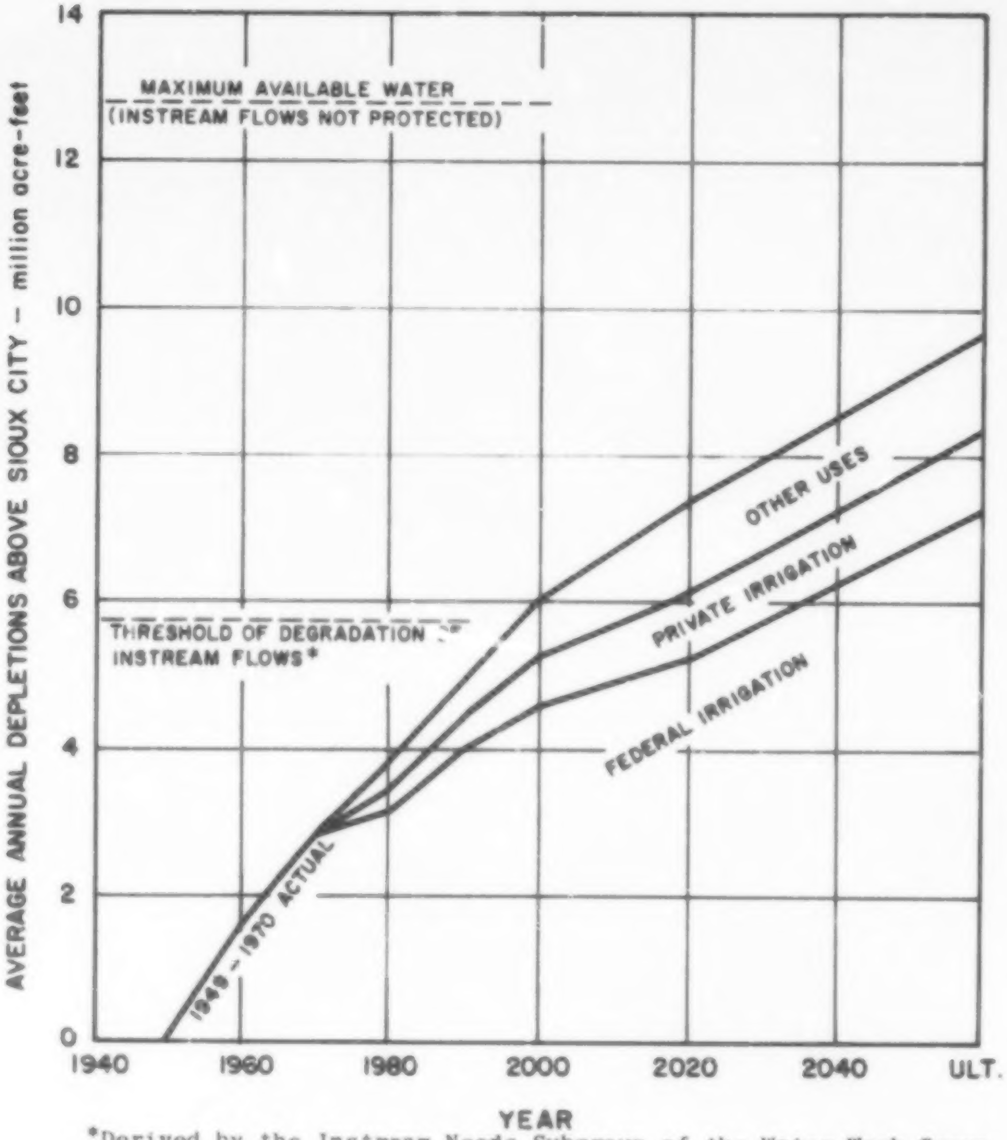
The water rights administration in the upper Missouri Basin is similar to that described for the Colorado Basin with some important differences. There is no treaty, compact, or agreement requiring the maintenance of a specified annual supply to the lower Missouri Basin as there is for the Colorado Basin. Thus, depletion applications are not denied unless they are contested and shown to be not to the public benefit. Water rights also generally attach to the land for which they are to be applied. The result has been the same as in the Colorado Basin, however. Many more applications for water rights have been approved and are in process than available supplies can support. The operations of the marketplace in the sale and transfer of rights will ultimately determine much of the future allocation of water use.

3. Present and Projected Nonenergy Uses

Figure IV-4 is a projection of water uses beyond 1970 developed by the Water Work Group.[6] Two limits are shown on the figure: the 10 million acre-feet per year limit of consumption and the threshold of degradation of instream flows derived by the Instream Needs Subgroup.[6] The "other uses" category includes municipal, industrial, and export uses. This projection indicates that the instream flow threshold will be exceeded before the year 2000 without considering additional energy projects. If instream flow requirements are to be met, a drastic curtailment of future irrigation and other water uses projects will have to take place within the next 20 years. It is also significant that if the instream flow degradation limit is ignored, the consumption limit will not be approached until more than a century passes.

4. Projected Energy Uses

The previous projection for nonenergy use suggest that 3 million acre-feet of water can be allocated to energy during the next century without reducing projected irrigation and other uses. The price will be an increased level of degradation of instream flows with a resulting reduction in the biologic and aesthetic values of the Basin, particularly in periods of drought. Another degradation is the reduction in the navigability of the Missouri River.[6] The mainstream storage system would not provide as long a navigation season as it now does. Presently, the navigation season on the upper Missouri is 88 percent of the time during more than eight months of the year. With the projected uses of agricultural and other nonenergy uses, this season will be reduced to average only 72 percent of the time during more than eight months of the year by the year 2000. If another million acre-feet of energy use is added, the navigation season is estimated to be reduced still further to



*Derived by the Instream Needs Subgroup of the Water Work Group.

SOURCE: Report of the Water Work Group, Northern Great Plains
Resource Program, April 1974

FIGURE IV-4. PROJECTED WATER CONSUMPTION FOR THE UPPER MISSOURI RIVER BASIN

give only about 60 percent of the time during eight months of the year.

In any case, it is seen that projected new energy projects of either direct burning of gasifying coal in the upper Missouri Basin are likely to involve only a small fraction of the total allocation for water use. There is more than adequate water for all projected uses including coal conversion projects if secondary environmental degradation, such as to instream flows and navigation, is ignored. If the secondary effects are to be avoided, however, a series of hard choices will have to be made primarily between agricultural commitments and energy development, and these will have to be faced within the next few years.

REFERENCES FOR CHAPTER IV

1. "Final Environmental Impact Statement for the Prototype Oil Shale Leasing Program," U.S. Department of Interior, Vol. I and III (1973).
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3. "Air/Water Pollution Report," p. 394 (October 7, 1974).
4. Townsend, S. and V. Laven, "An Economic Analysis of Alternative Technologies for Cooling Thermal-Electric Generating Plants in the Fort Union Coal Region," (1974).
5. "Synthetic Petroleum for Department of Defense Use," Stanford Research Institute (November 1974).
6. "Draft Report of Work Group (C) Water," Northern Great Plains Resource Programs, p. 61 (April 1974).
7. "Report on Water for Energy in the Upper Colorado River Basin," U.S. Department of Interior (July 1974).
8. "Final Environmental Impact Statement for the Prototype Oil Shale Leasing Program," DoI, Vol. I, II-30.

V. WATER POLLUTION POTENTIAL OF OIL SHALE AND COAL CONVERSION PROCESSES

A. Introduction

Of the fifteen alternatives for energy development analyzed in Volume II of this report, nine involve mining and conversion of coal or oil shale. The water pollution potential of these nine processes are discussed in this chapter. Water quality impacts of the other six (OCS oil, onshore Alaskan oil, OCS gas from the East and West Coasts and from Alaska, and the two forms of assisted recovery of oil) are discussed in their respective sections of volume two of this report.

The processes that convert oil shale and coal into oil, gas, and electricity consume large amounts of water. Excess water can be disposed of by evaporation, by mixing it with the solid waste and storing it in dump grounds either on the surface or in the mine, by well injection into deep underground aquifers, by discharge into a nearby river, or by recycling for reuse in the conversion process. The factors that govern the choice among these alternatives include local climate and geology, economics, water availability, and water quality impact on existing water resources. Because the technologies offer these many alternatives for disposing of excess water, current plans for new plants have chosen alternatives that make some compromise in response to the conflicting pressures of minimizing costs and meeting environmental impact standards. Thus, nearly all current plants for oil shale and coal conversion propose disposal of all excess water on-site without return to the river or reservoir from which it was obtained. Likewise, most current plans for conversion in the West call for extensive recycling of water for reduced use of high quality water to minimize depletion of relatively scarce supplies as well as to minimize the amount of excess water which must be disposed of in an environmentally acceptable manner. Another trend is evident in the increasingly serious consideration and use of dry cooling to reduce water consumption.

The effects on water quality of these water disposal alternatives has been gathered primarily from a review of several environmental impact statements for conversion processes and several water quality studies of these processes. These sources are listed in the References to this chapter.

Section B describes the conclusions of this analysis. Section C contains a discussion of the characteristics of water handling and processing as a background to a more direct discussion in Section D of each of the potential sources of water pollution.

B. Conclusions

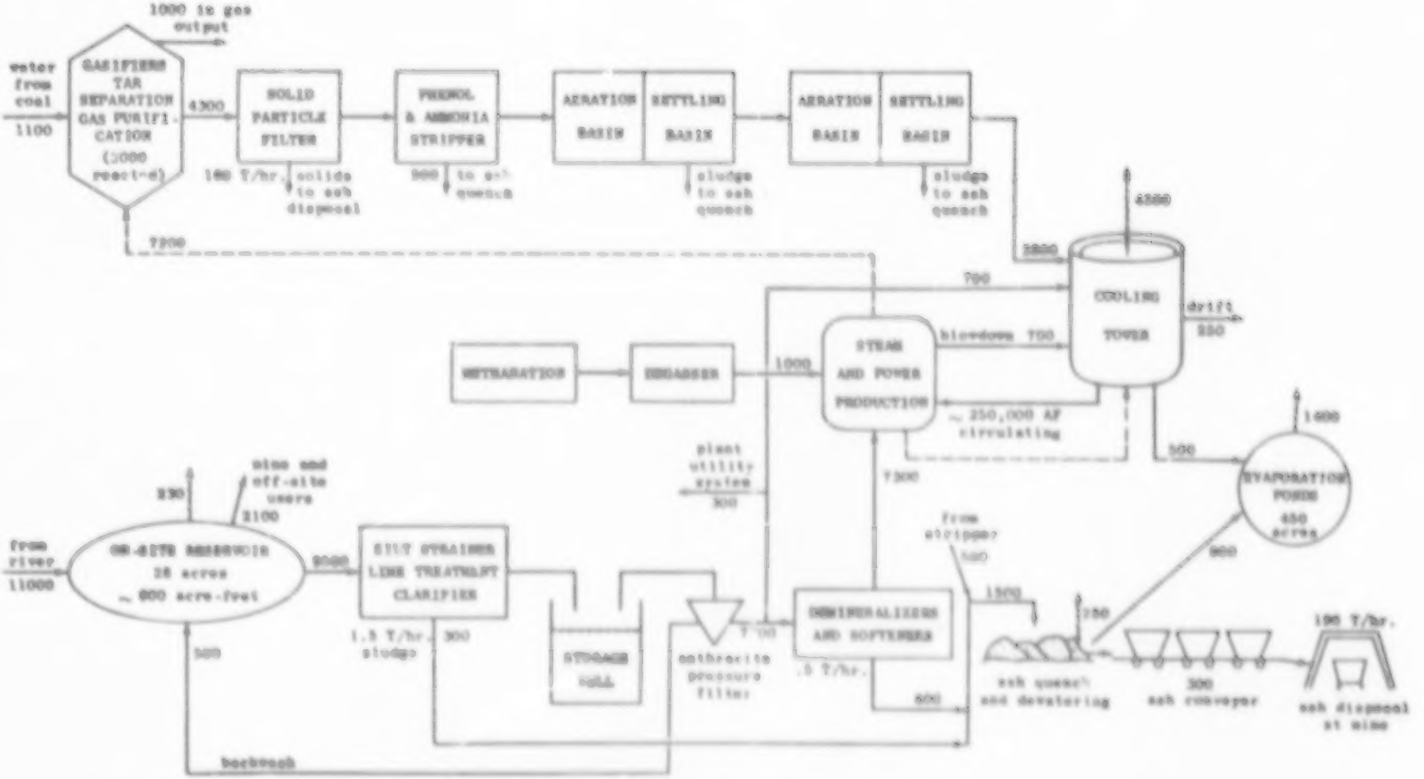
The major conclusions of this brief investigation of water quality impacts of oil shale and coal conversion processes are:

- Direct discharge of contaminated water into streams and reservoirs can be minimized if not eliminated at a cost. Measures to achieve this include evaporation ponds, treating and recycling waste water, deep underground injection of excess water, and provision of adequate catchment dams to impound water runoff from ash and spent shale disposal piles. Local climate and geology are important in determining technical feasibility and costs of the alternative measures.
- Inadequate data are available to assess the magnitude of indirect impacts such as contamination of underground aquifers and increasing the salinity of downstream flows by depletion of upstream water.
- More research is needed in the following areas:
    1. Potential aquifer contamination from underground mining operations.

2. Transport and surface discharge of highly saline deep underground water into streams; methods for mitigating these adverse impacts are being developed.
3. Transport of highly saline deep underground water into upper aquifers and discharge of the saline water into streams from pressure buildup due to deep well injection techniques.
4. Long-term buildup of salinity in downstream regions resulting from depletion of upstream sources.

C. Water Processing for Energy Conversion

Although it is not within the scope of this study to treat all of the many alternatives in water handling in each process, it is useful to examine one of the processes as a base case against which variations can be discussed. For that reason, a simplified diagram (Figure V-1) of the water and solid waste flow for the Lurgi gasification process has been developed from information provided by the El Paso Natural Gas Company Report on Environmental Factors for their Burnham coal gasification project[1] and an Exxon Research and Engineering Company study done for EPA.[2] The diagram shows water and solid waste flows only, not the gas and other product flows. The numbers have been rounded and, therefore, the material balances will not precisely close. Three sources provide the required 11,600 acre-feet per year of water: 80 percent is raw water from the San Juan River, 10 percent comes from the coal being processed, and the other 10 percent is produced in the methanation process. There are two treatment systems in the process. The first system chemically purifies the raw water for cooling tower feed and, with further treatment, the boiler feed for steam and power production; the second system treats the gas liquor from the gasifiers for recycling to provide additional cooling tower makeup water. Only 22 percent of the water provided is consumed in the reactions of the gasifier steps and another 10 percent is output in the gas produced. The remaining 68 percent is disposed of by evaporation (55 percent) and in the wet ash, ammonia byproduct, incineration, ventilation


water from coal
1100
GASIFIERS TAR SEPARATION GAS PURIFICATION (1000 react-d)
1000 to gas output
4300
SOLID PARTICLE FILTER
180 T/hr. solids to ash disposal
PHENOL & AMMONIA STRIPPER
900 to ash quench
AERATION BASIN
SETTLING BASIN
sludge to ash quench
AERATION BASIN
SETTLING BASIN
sludge to ash quench
2800
4500
7200
700
COOLING TOWER
drift 250
METHANATION
DEGASSER
1000
STEAM AND POWER PRODUCTION
blowdown 700
~ 250,000 AF circulating
1400
500
EVAPORATION PONDS 450 acres
plant utility system 300
7300
from stripper 900
900
from river 11000
230
mine and off-site users 2100
ON-SITE RESERVOIR 28 acres ~ 800 acre-feet
9000
SILT STRAINER LIME TREATMENT CLARIFIER
1.5 T/hr. sludge
300
STORAGE CELL
anthracite pressure filter
7100
DEMINERALIZERS AND SOFTENERS
.5 T/hr.
600
1500
250
ash quench and dewatering
300 ash conveyor
190 T/hr.
ash disposal at mine
500
backwash

SOURCES: El Paso Natural Gas Co. Revised Report on Environmental Factors, Burnham Coal Project, January 1974.
Evaluation of Pollution Control in Fossil Fuel Conversion Processes by Exxon Research and Engineering Co. for EPA, July 1974

LEGEND

Unlabeled numbers are acre-feet/year of water
Solid lines = water flow
Dashed lines - steam flow
Wiggly lines - evaporation

FIGURE V-1. SIMPLIFIED DIAGRAM OF AN EXAMPLE OF WATER AND SOLID WASTE FLOW FOR LURGI DRY ASH COAL GASIFICATION PROCESS FOR A 250 MILLION SCF PER DAY PLANT

of the steam and drift (mist) from the cooling towers, each accounting for 1 to 3 percent.

D. Water Quality Effects

The potential sources of water pollution from these processes are of three types: (1) those that arise from disposition of the water not consumed; (2) leaching of salts from solid water disposal piles; and (3) those that arise from the depletion of water sources to provide the required process supply. While it would be desirable to develop quantitative estimates of the degree of pollution resulting from each source, only limited estimates can be made owing to a lack of knowledge of the effects of leaching, diffusion, and transport mechanisms in underground aquifers and of the sensitivity of pollution to a multitude of parameters depicting the configuration of local geology, soil type, and subsurface hydrology of the region.

In the following section the origin and expected quantities of aqueous contaminants generated in coal and oil shale conversion processes are discussed. Thereafter, alternative methods for disposing of treated waste water and potential sources of indirect water contamination are set forth.

1. Origin and Treatment of Aqueous Contaminants

a. Coal Gasification

Most of the aqueous contaminants resulting from SNG production are generated during the coal gasification step. During this step, the coal is exposed to high temperatures and pressures in the presence of oxygen and steam. Organic impurities are formed from the release of volatile materials in the coal (tar, oil, naphtha and phenols) and gaseous impurities consisting of nitrogen compounds (ammonia and hydrogen cyanide) and sulfur compounds (hydrogen sulfide, carbon disulfide) are also formed. During the quenching step, the contaminated synthesis gas exiting the gasifier is scrubbed with water to condense the tar, oil, and naptha, which are decanted and recovered as byproducts. The remaining quench water (called gas liquor) containing dissolved ammonia, phenols, and other contaminants is sent to the gas liquor treatment unit. In this unit the phenols are separated as byproducts by means of the Phenosolvan process--a proprietary process of the Lurgi Corporation. The remaining solution containing mostly ammonia is sent to the ammonia stripper unit where concentrated ammonia solution is recovered, and hydrogen sulfide gas is removed and sent to the sulfur recovery unit. The remaining water is of high enough quality to be recycled for use in the cooling towers after treatment in the effluent water treatment unit (biological treatment section followed by aeration and residence in settling ponds).

The 2400 gallons-per-minute (3800 acre-feet per year) of water entering the effluent water treatment unit contains residual amounts of phenols and ammonia, as well as other contaminants such as fatty acids, suspended solids, BOD (biological oxygen demand), and other trace contaminants such as hydrogen cyanide. These contaminants are reduced to low levels by the biological treatment unit, aeration ponds, and settling basins. The levels of contaminants expected in the water discharged from the effluent water treatment section are shown in Table V-1.

b. Oil Shale

Most of the residual waste water from oil shale retorting and upgrading is used to moisturize the spent shale before disposal. Thus, the main potential for water pollution is in runoff or leaching from the spent shale pile. The 2700 gallons-per-minute (4350 acre-feet per year) of waste water used in this application (for a 100,000 bbl-per-day retorting and upgrading plant) consist of moisture generated in the retort and the gas recovery unit, excess moisture and process water from the coking unit,

Table V-1

AQUEOUS CONTAMINANTS IN TREATED SNG PLANT
RECYCLE WATER[a]

Contaminant	Concentration (ppm)
Phenols	3
Ammonia	5
Fatty acids	9
BOD	75
Suspended solids	5
Hydrogen cyanide	Trace
Hydrogen fluoride	Trace

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[a] Data from Reference 2

fuel gas and stack gas scrubbing water, cooling tower and boiler blowdown, and any mine drainage or spent shale pile runoff water that has been collected.[3]

Waste water containing ammonia and hydrogen sulfide is treated in the foul water stripper unit where the ammonia is recovered as a byproduct and the hydrogen sulfide is sent to the sulfur recovery unit. Other than this treatment there is no further processing of the waste water that is used to moisturize the spent shale. The levels of contaminants expected in this waste water, as estimated by Colony Development Operation, are listed in Table V-2.

c. Coal Liquefaction

The aqueous contaminants generated during coal liquefaction are similar to those generated by gasification, and treatment generally follows a similar path. Most of the contaminants originate in the coal hydrogenation step in which oxygen, nitrogen, and sulfur compounds are converted to water, ammonia, and hydrogen sulfide, respectively. Other sources of waste water are the boiler and cooling tower blowdown.

Table V-2

CONTAMINANT LEVELS OF WASTE WATER USED IN SPENT SHALE MOISTURIZING[a]

Contaminant	Concentration (ppm)
Sulfates	510
Thiosulfates	60
Carbonates	520
Phosphates	15
Chlorides	330
Cyanides	50
Hydroxides	30
Phenol	60
Ammonia	30
Amines	1900
Organic acids	1000
Chelates	3
Chromates	130
Arsenic	0.03

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[a] Data from Reference 3

Subsequent to treatment of the waste water in the foul water stripper unit and the biological treatment pond, the remaining 3500 gallons-per-minute (5600 acre-feet per year) of water effluent from a 100,000 bbl-per-day plant is expected to contain the levels of contaminants shown in Table V-3.

If the waste water is not recycled or disposed of on-site, then the above concentrations times the total quantity of water generated per day (21,000 tons) represents the quantities of contaminants which could be discharged daily.

Table V-3

LEVELS OF CONTAMINANTS IN TREATED COAL LIQUEFACTION PLANT WASTE WATER[a]

Contaminant	Concentration (ppm)
Sulfide	0.005
Ammonia	0.11
Oil	0.68
BOD	10.5
Suspended solids	12.9
Phenol	0.38
COD (chemical oxygen demand)	45
Phosphate	0.11
Chromate	7.1
Zinc	3.5

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[a] Data from Reference 4

2. Disposition of Unconsumed Water

The primary means of disposition of excess water shown in Figure V-1 is evaporation from large ponds. No estimate for the size of the ponds was given in the sources used for the diagram. However, a simple calculation using a net evaporation rate of three feet per year, which is typical of the Northern Great Plains Region, yields an estimate of 450 acres. This water is highly contaminated with salts from the original supply and minerals from previous processing use. Seepage from these ponds can present a severe pollution threat to nearby surface aquifers, streams, and wells. There are several alternatives to reduce this pollution. These are:

a. Lined Evaporation Ponds

A clay, such as bentonite, can be used as an impermeable barrier. Such a lining would be highly effective in practically eliminating seepage. Although bentonite is inexpensive, transportation and lining costs can be high.

b. Injection into Deep Underground Aquifers

This alternative involves drilling deep wells (1000 feet or more) in a spaced pattern and pumping the excess water into a highly saline deep aquifer. A Department of Interior Study^5 (DoI) estimated a pumping rate of 1 cfs (725 acre-feet per year) for each well.* Thus, two wells would be required for 1400 acre-feet per year in the example shown in Figure X-1. This injection is likely to increase hydrostatic pressure in the lower aquifer, resulting in increased leakage of lower aquifers either laterally or to upper level aquifers and in a raised water table in the region. The DoI study estimates a hydrostatic head change of 122 feet midway between two wells two miles apart after 30 years. The significance of this increased pressure for water quality lies in the migration of highly saline deep aquifers toward the surface with resulting contamination of wells and streams. In addition, the higher water table would result in increased discharge into the creeks in the area, resulting in a greater load of dissolved solids being dumped into the main river system. For example, the DoI study estimates that an increased discharge of 5 to 30 cfs of water with 1000 to 2000 mg/l of dissolved solids into the Piceance Creek in the oil shale region of Colorado would add from 13 to 161 tons per day of salt to the Colorado River system, approximately doubling that which is already added by the Piceance Creek. This increased salt load will raise the salinity of the water at Hoover Dam by about 4 mg/l. While this effect is not great from one plant, if it were multiplied 10 to 20 times corresponding to this number of plants, degradation of the water of the Colorado River could result.† The smaller rivers in the Northern

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*The Department of Interior study has been challenged on this point by industrial sources who assert the aquifers cannot sustain an injection rate that high.

†Not all oil shale projects will require dumping and disposal of brackish water.

Great Plains region may be even more sensitive to this effect, although no analysis has been found.

c. Treatment of the Excess Water and its Discharge into the Source River

This alternative, like that of lining the evaporation ponds, would involve primarily increased cost. Technology for adequate removal of the highly concentrated salts and other impurities in the water resulting from coal and oil shale processing has not been demonstrated. The fact that few proposals involving coal conversion or oil shale processing include this as a viable option suggests that it is not economically attractive.

d. Reduction of the Water Discharged by Reducing the Water Requirements

There are two primary ways by which water consumption can be reduced. The first of these is the use of partial or complete dry cooling instead of wet cooling. In a wet cooling tower, such as is illustrated in Figure V-1, the circulating water is brought into direct contact with air, which is forced past the water with fans. Cooling takes place by evaporation. Makeup water to replace that evaporated, lost by drift (particle mist), and blown down (i.e., water removed to carry away salts and sediment buildup) must be supplied at a rate of about 2 to 2-1/2 percent per year of that which is kept circulating.* In Figure V-1, this amounts to about 5200 acre-feet per year, which is more than half of the total input requirement of 9500 acre-feet per year. Dry cooling of part or all of the circulating water could thus reduce the input requirement by as much as half.

Dry cooling is an alternative in which the circulating water is kept in a closed system. Air is forced past the heat transfer surface and cools by conduction and radiation. Thus, no water is lost and no makeup is required. There are three disadvantages to air cooling:

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*The feed rate can be as high as 7 percent, depending on the total salt content and ion makeup of feedwater.

(1) Because of the large surface area required for heat transfer and large amounts of air needed to be circulated, the cost of this process is much higher than water cooling.

(2) The efficiency of cooling depends on air temperature which, in the absence of refrigeration which would greatly add to the cost, depends on the weather. Thus, during periods of warm weather, the cooling efficiency is greatly reduced. This lower efficiency may require reduction or even shutdown of the plant operation during those periods.

(3) There are no dry cooling towers at power plants in this country of a size comparable to that required for this plant. Thus, the engineering and operation of such a facility have not been fully established.

To take advantage of the reduced water makeup requirement of dry cooling to lower water input requirements, the gas liquors from the gasification process must be treated to a degree sufficient to be recycled to provide part of the steam boiler makeup water. This water is otherwise supplied from the raw water treatment facility. The treatment required may include activated carbon adsorption or evaporative distillation and chemical oxidation, in addition to stripping and biological treatment.

3. Leaching of Salts from Waste Disposal Piles

Coal gasification and liquefaction and oil shale retorting produce large amounts of solid waste. In the example of coal gasification shown in Figure V-1, this amounts to over 1.5 million tons per year.*

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* This is based on 18 percent ash in the coal feedstock. Ash content of coal may vary from 8 percent for North Dakota lignite and Powder River subbituminous to 19 percent for New Mexico subbituminous.

Most proposals plan to dispose of this material in piles on the surface, either to cover portions of the surface mine, or to fill valleys set aside for that purpose. In either case, water runoff from these piles is highly saline and carries a heavy load of dissolved solids. Runoff channels and catchment dams are planned to hold the runoff and keep it from entering local streams. The possible failure of such a catchment system during a storm has been analyzed by the Department of Interior.[5] An example of a 100-year maximum rainfall of 2.5 to 3 inches falling in a six-hour period on a 700-acre spent shale pile at a particular location near Piceance Creek was used. The resulting salinity was calculated to be about 200 mg/l in Piceance Creek, assuming that 2 to 4 inches of the surface of the shale pile was totally leached and went into the nearby creek. The reason for the small increase in salinity is the great increase in water from the storm, which would mix with the leached shale in the creek. This one example suggests that leaching of salts into nearby streams may not cause serious degradation of water quality if catchment dams are maintained to restrain the runoff from regular rainfall and snow melt.

4. Contamination of Aquifers

The possibilities of aquifer contamination by highly saline waters can be described in terms of a specific example pertinent to oil shale development in Colorado.

The Green River formation of the Piceance Valley contains a deep highly saline aquifer and an alluvial surface aquifer with high quality water. These are separated by the relatively impermeable Mahongany Formation, which is rich in oil shale. Stripping or penetrating the Mahongany Formation to mine the oil shale may result in contamination of the surface alluvium by the ground saline waters underneath. Since the alluvium discharges into the surface streams, increased salinity of the stream flows could result. Another possibility is the seepage of runoff from the spent shale piles into the alluvial aquifers and subsequent discharge into local streams. Neither of these effects has been subjected to detailed analysis so that their magnitude can only be speculated. The effect of aquifer contamination might be more important than the storm runoff effect because it will be a continuous rather than short-term addition of saline water to local streams.

5. Increase of the Salinity of Downstream Flows From Upstream Depletion

Oil shale development in the Piceance Creek Basin will draw water from the relatively large Colorado River, while coal processing in the upper Missouri Basin will draw water from the Missouri River and its many smaller tributaries. Because there is a difference in the configuration of water resources in the two basins, the potential for significant increases in salinity of these resources due to water consumption by coal and oil shale industries is different in character. Thus, each case will be discussed separately.

a. Salinity Impacts on the Colorado River

The salinity impact of water requirements of 80,000 acre-feet per year for 10^{15} Btu of oil from oil shale on the Colorado River at Parachute Creek can be illustrated by an oversimplified calculation. The salinity of the Colorado River at Parachute Creek is approximately 450 mg/l, while at Hoover Dam it is 730 mg/l. Removal of 80,000 acre-feet of water at Parachute Creek will increase the salinity at Hoover Dam by 0.3 of 1 percent; i.e., from 730 to 732. Although this salinity increase is not large relative to the present levels, a $280 million program was enacted by Congress in June 1974 to control the salinity of the Colorado River, particularly below the Imperial Dam where the river enters Mexico. Furthermore, although salinity standards are presently in the process of being proposed by the states with a submission date of October 1975, it has been a basic policy promulgated by EPA that the salinity of the lower

Colorado River is to be maintained at or below 1972 levels. These factors suggest that any increase in salinity resulting from energy development will have to be controlled at some cost.

b. Salinity Impacts on the Streams of the Upper Missouri Basin

The upper Missouri Basin consists of many small rivers interlocked in a complex network that feeds the Missouri River. The problem of supplying water to 20 or more coal-burning power plants or coal gasification plants is thus a difficult problem in water management. Several detailed scenarios were worked out in the Northern Great Plains Resources Program Study in which power plants and gasification plants were carefully located with respect to water supplies and the added dams and aqueducts necessary were located.[6] By using very much oversimplified models of effects of water depletion of the salinity of the rivers affected, that study showed that at high levels of energy development coupled with relative drought conditions in which flows were reduced to that considered minimal for the support of aquatic life, salinity levels might rise to greater than 1000 mg/l on some rivers. This level of salinity is one at which salt-sensitive crops are affected. The study emphasizes the inadequacy of the assumptions used in the calculations, however, and recognizes the need for a more comprehensive study of the effects of heavy energy industry water depletion on the salinity of the small rivers and streams.

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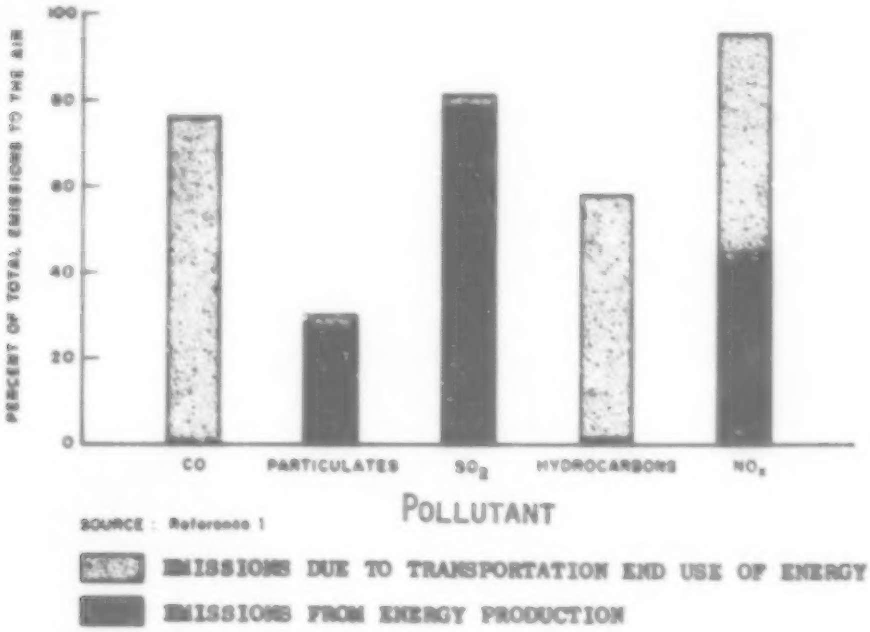
VI. AIR POLLUTION IMPACTS OF OPTIONS TO INCREASE U.S. ENERGY SUPPLY

A. Introduction

1. Relationship Between Air Pollutants and Energy Production

The production and use of energy are responsible for the majority of emissions of hazardous pollutants to the air in the United States. For the pollutants for which EPA has established ambient air quality and some performance standards—CO, particulates, SO_2, hydrocarbons, and NO_x—the contribution of emissions due to energy-related activities are shown in Figure VI-1 below.[1] The blackened portions of this figure indicate



SOURCE : Reference 1

FIGURE VI-1. ESTIMATED EMISSIONS OF AIR POLLUTANTS BY WEIGHT DUE TO ENERGY PRODUCTION AND USE (1970)

that, relative to the emissions from other sources, SO_2, NO_x, and particulates, are of greatest significance to a consideration of air quality impacts of energy production.

In addition to SO_2, NO_x, and particulate emissions, there is cause for concern about other categories of pollutants derived from energy production. Specifically, emissions of small particles (those less than 1 or 2 microns in diameter), various trace metals (such as lead, mercury, vanadium, copper, arsenic), radioactive particles, and substances that can contribute to the formation of photochemical smog can be related directly to energy production. Little quantitative assessment has been made of the impacts of these pollutants for which neither air quality nor performance standards have been set; of special importance is the need for quantitative work relating emissions of these pollutants to the different energy and nonenergy related sources. The last section of this chapter contains a simple model which provides a means of determining which trace metal emissions have the potential for causing ecological or health-related damage. To our knowledge, this is the first attempt which has been made to obtain a semi-quantitative indication of the significance of trace metal emissions and impacts for a broad range of trace metals.

2. Methodology

The intent of this chapter is to provide sufficient data and analysis to form the basis for a relative ranking of the energy augmentation measures with regard to air pollution impacts. The most complete data are those for emissions to the air arising from the energy conversions processes. These emissions have been converted to a common unit, tons of pollutants per 10^{12} Btu output. This unit of emission of air pollutants takes into consideration the efficiency of the process. For example, the output energy of a coal-burning power plant of 1000 MW(e) operating at 70 percent load factor is about 2.2×10^{13} Btu per year, while the energy value of the coal input into the plant is approximately 6.6×10^{13} Btu per year. Our accounting procedure scales all emissions to total output (or useful) energy available at the point of end use.

The major objective of this chapter is to provide a common basis for the estimation of emissions to the air of the different energy conversion technologies. We have found it necessary to analyze assumptions made with respect to the efficiency of abatement technologies in removing a given pollutant from a stack gas or other potential flow to the atmosphere. Simplified flow diagrams are used to pinpoint the source of emission, assumptions made about control, and alternative ways of increasing or decreasing the level of control. In general, we have assumed a level of abatement technology presently available for the construction of new energy facilities. An important exception to that assumption occurs for instances in which new federal performance standards require control technology less efficient than is presently attainable. For example, a new coal plant built in the West may meet federal new source performance standards for SO_2 using low-sulfur coal and scrubbers of about 40 percent efficiency, in spite of the fact that much more efficient scrubbers are apparently available for implementation. We assume the use of the less efficient scrubbers for cases in which the utilities plan to just meet the federal performance standards, as required.[5]

The emission data for options that produce electricity cannot be compared directly with those that produce petroleum or natural gas, because of the great differences in the nature, efficiency, and polluting impact of their end uses. For example, if the petroleum produced from oil shale is used to generate electricity, then its useful energy content is reduced by two-thirds and the total air pollution per 10^{12} Btu output ultimately traced to the oil shale is the sum of the additional emission due to conversion of oil to electricity plus three times the emission due to the production of 10^{12} Btu of synthetic crude from shale. Since the range of end uses of petroleum and natural gas is so vast, it is difficult to make a direct comparison of emissions for the liquid, solid, and gaseous forms of energy. As a simple rule of thumb, it is probably useful to multiply emissions from options that produce oil by two to three and emissions from options which produce pipeline quality gas by one to one and one-half, in order to arrive at a very approximate comparison with emissions from the production of electricity.

Comparison of data on emissions to the air of alternative methods of producing a given form of energy represents a first step in arriving at judgments on the relative air pollution impacts of the methods. Further analysis to refine judgments based on emission data includes consideration of:

- Local and regional weather conditions.
- Population at risk.
- Background ambient air concentrations of pollutants.
- Local and regional topography.
- Impact on health and welfare of specific pollutants, acting alone or in concert.

It is beyond the scope of this work to evaluate these considerations quantitatively; nor is it necessary to do so to arrive at a relative rather than absolute judgment of the air pollution impacts of the different technologies. Nonetheless, qualitative considerations of these factors have been included in the analysis in the relevant sections of volume two of this report to illustrate the trade-offs involved in different siting choices and to provide some measure of the potential severity of the air pollution problem.

B. Emissions of Pollutants to the Air from Energy Production Technologies

1. Sources of Emissions

The quantities of various air pollutants emitted during energy conversion and production processes depends strongly on the nature of the technology employed and the nature and composition of the fuel processed. As in all manufacturing processes in which raw materials are transformed into a final product, fuel must be consumed to provide steam, heat, and electricity to drive the component mechanical and chemical steps that make up the overall conversion or production process. This consumption of fuel provides the largest contribution to the air emissions associated with energy production and conversion. In addition, contaminants such as sulfur or trace elements, which are initially present in the resource, can be removed or otherwise chemically transformed during processing, and inevitably some leakage to the air will occur. This effect is the other major contributor to air pollutant emissions.

Since nine of the fifteen alternatives considered for increasing domestic energy supplies involve the conversion of coal or oil shale (one case) to other forms of energy, we will focus on these technologies. In general these technologies are themselves very consumptive of energy. Between 1.5 and 1.8 units of resource energy in the form of coal or oil shale are required to produce one unit of gaseous or liquid fuel. Approximately 0.3 to 0.5 units are consumed as fuel to run the process, and the remainder are lost as waste heat during conversion. The quantities of air pollutants emitted depend on the form of the fuel consumed. In many processes, significant quantities of combustible gases, liquids, or solids are obtained as byproducts during conversion. These can be utilized as plant fuel. If additional energy is required, then either the resource itself or some of the end product can be consumed.

The removal of sulfur during the conversion of coal or oil shale to liquids or gases is an important step in mitigating the environmental effects of energy consumption. In almost all cases, the sulfur present in the resource is recovered as elemental sulfur, which can be sold as such, converted to sulfuric acid or, if necessary, stored. During the process of sulfur recovery, from 0.5 to 2 percent of the sulfur in the resource will be emitted to the atmosphere as SO_2. For high-sulfur midwestern coal, these quantities can become significant.

Stack gases from fuels combustion and tail gas from sulfur conversion plants will generally not be vented to the atmosphere without some sort of cleanup treatment for removal of SO_2 and particulates. In calculating quantities of emissions to the air, we have assumed levels of control that we believe to be within the capability of present or near-term technology. The level of control of particulate emissions from stack gases is assumed to be 99.5 percent using electrostatic precipitators or Venturi scrubbers. Other controls, such as fabric filters, may be somewhat less efficient, depending on the source of emissions.

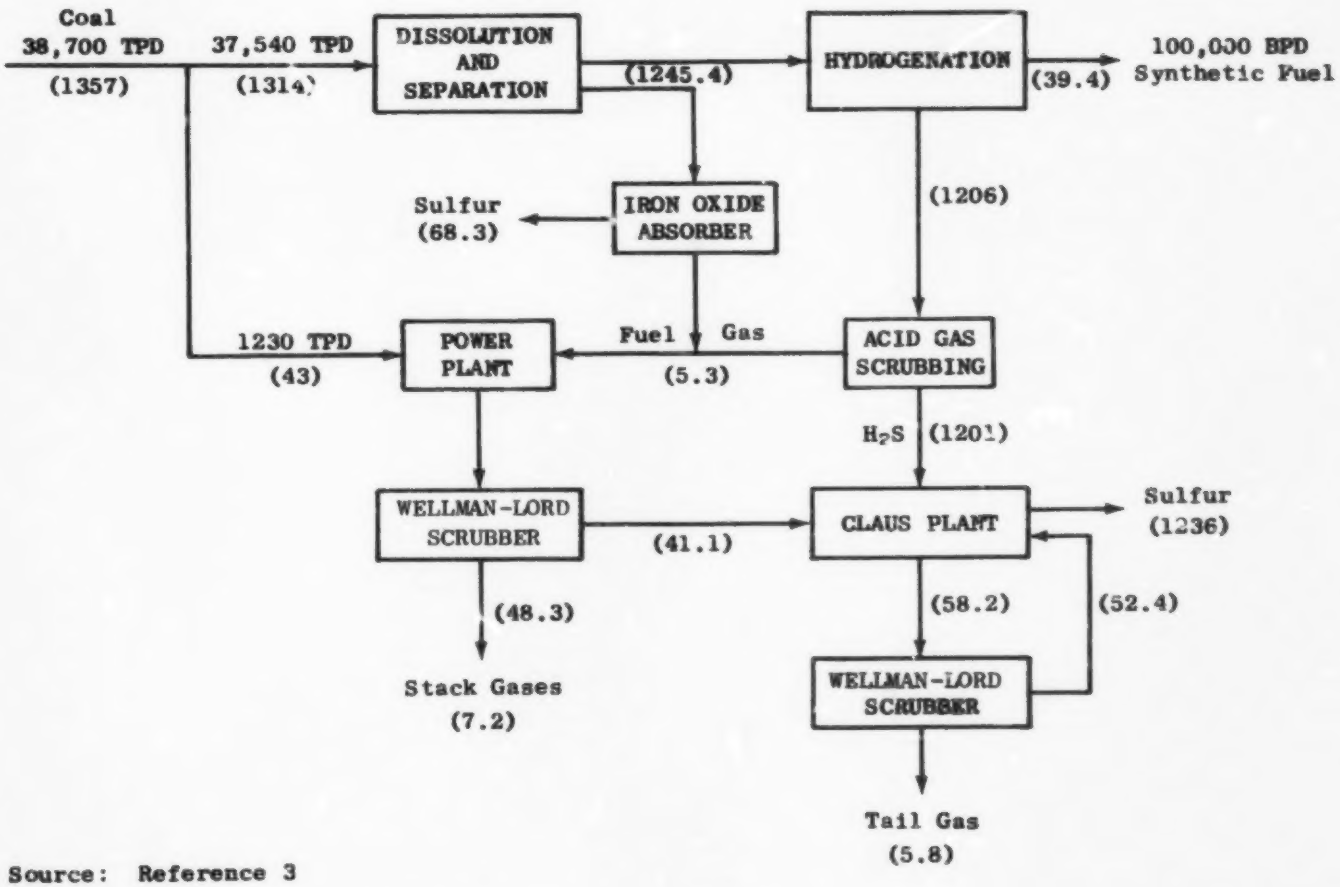
The level of control of SO_2 from stack gases is a subject of controversy between industry and the EPA. However, recent data suggest that SO_2 reduction levels of approximately 90 percent can be attained with varying degrees of reliability, using wet limestone scrubbing or similar technology.[2] We have chosen a somewhat optimistic reliability factor of 95 percent, resulting in a time-averaged net removal efficiency of 85 percent. For the recovery of sulfur from plant tail gas emissions, the SO_2 is in a much more concentrated form, and thus a removal efficiency of 95 percent has been chosen. Again, the reliability is assumed to be 95 percent, so that a net time averaged efficiency of 90 percent is attained.

Since emissions of SO_2 are likely to constitute the most serious air pollution problem for a number of the energy technologies addressed, we have attempted to illuminate the origin of these emissions by tracing the path of sulfur through two coal conversion processes. As examples, we have chosen liquefaction of midwestern coal via the CSF process, and production of SNG from western coal via the Lurgi process.

Figure VI-2 is a simplified flow chart and sulfur balance for the CSF coal liquefaction process. We have shown a plant which converts 38,770 tons per day of 22 million Btu per ton, 3.5 percent sulfur midwestern coal into 100,000 barrels of low-sulfur (about 0.25 percent) synthetic liquid fuel. Assuming the levels of control discussed above along with a 95.5 percent efficient Claus sulfur recovery plant, some 26 tons of SO_2 are emitted per day, with 55 percent of this amount resulting from the combustion of high-sulfur coal and byproduct gases to provide process heat, steam, and electricity. Since the ultimate product of a Wellman-Lord scrubber is SO_2, it has been assumed that it is recycled through the Claus plant. The source of the main feed to the Claus plant is a stream of H_2S and CO_2, which results from the acid gas scrubbing system. This system, of which the Rectisol and amine systems are examples, removes most of the H_2S, along with CO_2, which is present in the byproduct gases. The remaining H_2S is converted to SO_2 during combustion of these gases in the power plant.

Based on the analysis illustrated in Figure VI-2, 91 percent of the sulfur present in the feed coal is recovered as elemental sulfur, 5 percent is contained in the solid waste, 3 percent is contained in the product synthetic fuel, and 1 percent is emitted to the air as SO_2.

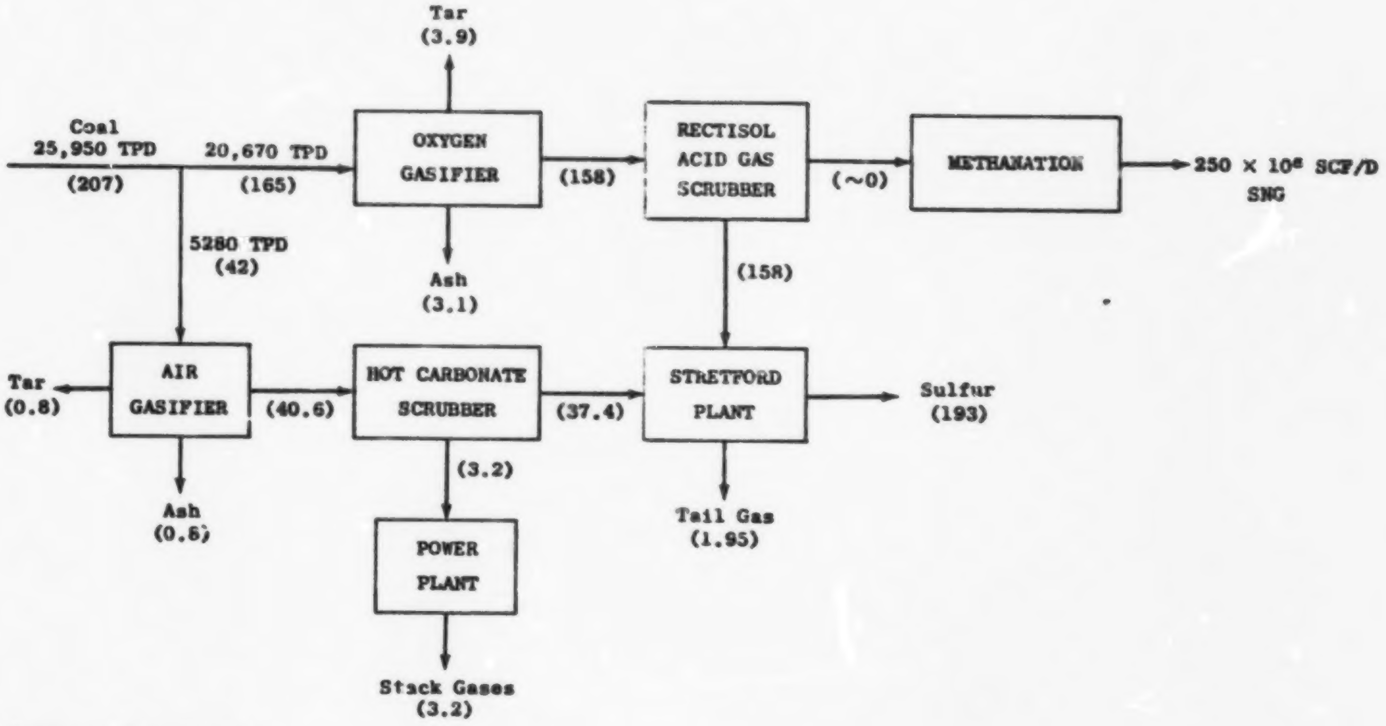
Figure VI-3 is a simplified flow chart that illustrates the sulfur balance for a plant that converts 25,950 tons per day of 18 million Btu per ton, 0.8 percent sulfur western coal into 250 million cubic feet of synthetic natural gas. The Lurgi coal gasification process is used


Coal
38,700 TPD
(1357)
37,540 TPD
(1314)
DISSOLUTION AND SEPARATION
(1245.4)
HYDROGENATION
(39.4)
100,000 BPD Synthetic Fuel
Sulfur
(68.3)
IRON OXIDE ABSORBER
(1206)
1230 TPD
(43)
POWER PLANT
Fuel Gas
(5.3)
ACID GAS SCRUBBING
H₂S (1201)
WELLMAN-LORD SCRUBBER
(41.1)
CLAUS PLANT
Sulfur
(1236)
(48.3)
Stack Gases
(7.2)
(58.2)
(52.4)
WELLMAN-LORD SCRUBBER
Tail Gas
(5.8)

Source: Reference 3

Note: Numbers in parentheses are tons per day of sulfur.

FIGURE VI-2. LIQUEFACTION OF 3.5 PERCENT SULFUR MIDWESTERN COAL VIA THE CONSOL SYNTHETIC FUEL PROCESS: SULFUR BALANCE



Coal
25,950 TPD
(207)
20,670 TPD
(165)
5280 TPD
(42)
Tar
(3.9)
OXYGEN GASIFIER
Ash
(3.1)
(158)
RECTISOL ACID GAS SCRUBBER
(~0)
METHANATION
250 × 10⁶ SCF/D SNG
(158)
Tar
(0.8)
AIR GASIFIER
Ash
(0.6)
(40.6)
HOT CARBONATE SCRUBBER
(3.2)
POWER PLANT
Stack Gases
(3.2)
(37.4)
STRETFORD PLANT
Sulfur
(193)
Tail Gas
(1.95)

Source: **Reference 4**
Note: **Numbers in parentheses are tons per day of sulfur**

FIGUPE VI-3. HIGH-Btu GASIFICATION OF 0.8 PERCENT SULFUR WESTERN COAL VIA LURGI PROCESS: SULFUR BALANCE both to provide medium-Btu synthesis gas for methane production and to provide a low-Btu gas as fuel to power the plant. Approximately 20 percent of the total feed coal to the plant must be utilized in the form of low-Btu gas to provide plant fuel. Even though the low-Btu gas is scrubbed to remove H_2S, some H_2S remains in the gas and is emitted to the air as SO_2 during combustion. This process contributes 62 percent of the total SO_2 emissions.

Almost all the H_2S in the synthesis gas must be removed prior to methanation, since sulfur destroys the effectiveness of the methanation catalyst. This removal is accomplished by use of the Rectisol process. The resulting dilute H_2S stream is sent to the Stretford plant where 99 percent of the H_2S is converted to elemental sulfur, and the remaining tail gas is incinerated, yielding the other 38 percent of total SO_2 emission.

For the process described above, 93 percent of the sulfur in the feed coal is recovered as elemental sulfur, 2.5 percent is emitted to the air as SO_2, and essentially none is present in the final product SNG.

2. Quantitative Estimates of Emissions

Tables VI-1 through VI-3 list the emissions to the air of SO_2, particulates and NO_x for all energy production and conversion technologies for which we have been able to make quantitative estimates. The units for the emissions are tons per 10^{12} Btu of useful product energy, the product being either electricity, hydrocarbon liquids, or pipeline quality gas. The footnotes incorporated into each table list the references from which emission data were taken along with information on the sources of emissions from each process and assumptions used regarding controls of emissions.

Where a range of numbers is given in any entry, there is either uncertainty in the quantity of the emission or there are variations in

Table VI-1

SO_2 EMISSIONS RESULTING FROM
TECHNOLOGIES FOR INCREASING
U.S. ENERGY SUPPLIES

Reproduced from
best available copy.

Technology	Tons SO_2 per 10^{12} Btu Product Energy
I. Electricity	
A. Direct burning of western coal[a]	430-1800
B. Low-Btu gasification of western coal followed by combined cycle	
1. Lurgi[b]	57
2. Koppers-Totzek[b]	60
3. Fluidized Bed[c]	41
II. Liquid Fuels	
A. Extraction of oil from oil shale[d]	
1. TOSCO II[d]	98-120
2. Paraho[d]	70
3. In-situ[d]	100
B. Liquefaction of western coal	
1. SRC[e]	20
2. CSF[f]	38
3. H-Coal[g]	63
C. Liquefaction of midwestern coal	
1. SRC[h]	76
2. CSF[i]	70
3. H-Coal[j]	55
D. Assisted recovery of oil	
1. Micellar flood and CO_2 miscible[k]	<1
2. Steam injection[l]	280-560
III. Pipeline Quality Gas	
A. Gasification of western coal	
1. Lurgi[m]	30-60
2. Synthane[n]	60
3. Hygas (steam-oxygen)[p]	76
B. Gasification of midwestern coal	
1. Synthane[q]	230
2. Hygas (steam-oxygen)	380

Assumptions

[a] Data from Ref. 5. Assumes 18 million Btu/ton, 0.8 percent sulfur, 8.3 percent ash western coal. Lower limit is with 85 percent efficient limestone scrubber or similar control. Upper limit is with 40 percent control as proposed in Colstrip, Montana plant to meet federal new source performance standards.

[b] Data from Ref. 3. Assumes western coal as above. Half of SO_2 emissions are from sulfur recovery and half from combined cycle. 99 percent of H_2S in low-Btu fuel gas recovered by hot carbonate scrubbing and sent to Claus plant where 90 percent of sulfur is recovered. 90 percent of Claus tail gas H_2S is removed by Wellman-Lord or similar process.

[c] Data from Ref. 6. Assumes western coal as above. One third of emissions are from combined cycle and two-thirds from sulfur recovery. 99.5 percent of H_2S in low-Btu fuel gas is removed by calcined dolomite panel bed filter. Recovered SO_2 is reduced 50 percent prior to venting to atmosphere.

[d] Data from Refs. 7 and 8. SO_2 emissions from TOSCO II result mainly from the combustion of process-derived fuels (gases, C_4-liquids and fuel oil) to provide plant heat, steam and electricity. Main sources are shale preheating systems, electricity generation, hydrogen reforming furnaces and utilities boilers. Higher figure is original estimate from Ref. 7. Lower figure is revised estimate from Ref. 8. Paraho and in-situ retort emissions are estimates from Ref. 8; upgrading emissions have been added to derive totals.

[e] Data from Ref. 3. Assumes western coal as above. 25 percent of emissions from combustion of coal and process derived gases, 75 percent from sulfur recovery. Most of H_2S formed in liquefaction is scrubbed from off-gas and sent to Claus plant where 90 percent of sulfur is recovered. Tail gas emissions reduced 90 percent by Wellman-Lord unit.

[f] Data from Ref. 3. Assumes western coal as above. Nearly two-thirds of SO_2 emissions result from burning coal to provide external electricity requirement. 10 percent of emissions from coal and fuel oil-fired steam plant (85 percent efficient stack gas scrubbing assumed) and remainder from sulfur recovery. Claus plant recovers 95 percent of sulfur in H_2S stream from acid gas scrubbing, Wellman-Lord unit reduces Claus tail gas emissions by 90 percent.

[g] Data from Ref. 9. Assumes western coal as above. Combustion of coal and process-derived gases to provide plant steam and heat contribute 33 percent of total emissions (assuming 85 percent efficient stack gas scrubbing). Electricity generation contributes 30 percent. Remainder is from Claus plant sulfur recovery utilizing 95 percent efficient tail gas cleanup.

[h] Data from Ref. 3. Assumes 22 million Btu/ton, 3.5 percent sulfur, 11 percent ash midwestern coal. Emissions are due to combustion of coal and byproduct gases in the power-steam plant (24 percent) and sulfur recovery in 88 percent efficient Claus plant followed by 90 percent efficient Wellman-Lord tail gas cleanup.

[i] Data from Ref. 3. Assumes midwestern coal as above. Tail gas emission from 95.5 percent efficient Claus plant sulfur recovery followed by 90 percent efficient Wellman-Lord cleanup contributes 20 percent to total. Combustion of coal and fuel gases in steam plant with 85 percent efficient Wellman-Lord scrubber contributes 35 percent, and external electricity generation contributes the remainder.

[j] Data from Ref. 9. Assumes midwestern coal as above. Combustion of fuel gas for power plant, steam and heat contributes less than 1 percent. Remainder results from 95 percent efficient Claus plant followed by 90 percent efficient Wellman-Lord tail gas unit (60 percent) and coal combustion for electricity generation (40 percent).

[k] By analogy with primary recovery, emissions are small.

[l] Results from the combustion of 1 to 2 percent sulfur residual oil necessary to convert five barrels of water to steam for every barrel of oil recovered. No controls assumed.

[m] Data from Refs. 3, 4 and 10. Assumes 18 million Btu/ton, 0.8 percent sulfur, 8.3 percent ash western coal. Lower figure results if coal is converted to low-Btu gas which is then combusted to provide process heat and steam. In this case, SO_2 emissions are nearly equally divided between stack gases and Stretford plant tail gas. Higher figure results if coal is burned directly in power plant. Then with 85 percent effective scrubbing, stack gas emissions account for 83 percent of SO_2, remainder results from sulfur recovery tail gas.

[n] Data from Ref. 3. Assumes western coal as above. Power plant burns a combination of coal and byproduct char from gasification, resulting in about half of total SO_2 emissions, assuming 85 percent effective stack gas scrubbing. 90 percent efficient Claus sulfur recovery followed by 90 percent efficient Wellman-Lord tail gas unit accounts for the other half.

[p] Data from Ref. 3. Assumes western coal as above. Based on 96 percent efficient Claus plant sulfur recovery and 90 percent tail gas cleanup, 12 percent of SO_2 emissions are from this source. Then 88 percent results from power plant burning char and coal, with 85 percent SO_2 removal from stack gases.

[q] Data from Refs. 3 and 11. Assumes 22 million Btu/ton, 3.5 percent sulfur, 11 percent ash midwestern coal. With 85 percent SO_2 removal via stack gas scrubbing, and 96 percent sulfur recovery in Claus plant followed by 90 percent effective tail gas cleanup, 61 percent of SO_2 emissions are from coal and char-fired power plant and 39 percent are from sulfur recovery.

[r] Data from Ref. 3. Assumes midwestern coal as above. Over 90 percent of total SO_2 emission results from burning high-sulfur content char, coal and off-gas in power plant (85 percent stack gas scrubbing assumed). Remainder comes from sulfur recovery plant tail gas.

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Table VI-2

PARTICULATE EMISSIONS RESULTING FROM TECHNOLOGIES FOR INCREASING U.S. ENERGY SUPPLIES

Technology	Tons Particulates per 10^{12} Btu Product Energy	Assumptions
I. Electricity		
A. Direct burning of western coal[a]	64	[a]Data from Ref. 3. Assumes 18 million Btu/ton, 0.8 percent sulfur, 8.3 percent ash from western coal. Particulates reduced 99.5 percent by Venturi scrubber.
B. Low-Btu gasification of western coal followed by combined cycle		
1. Lurgi[b]	39	[b]Data from Ref. 3. Assumes western coal as above. All emissions from combined cycle, assuming particulate loading of 0.020 grains/SCF in low-Btu gas.
2. Koppers-Totzek[c]	19	[c]Data from Ref. 3. Assumes western coal as above. Six percent of emission results from combined cycle assuming 0.008 grains/SCF particulate loading of low-Btu gas. Remainder comes from coal-fired thermal dryer, assuming 99 percent efficient Venturi scrubbing.
3. Fluidized bed[d]	2	[d]Data from Ref. 4. Assumes western coal as above. Only source of emission is assumed to be 0.01 percent leakage from gasifier. Panel bed filter achieves greater than 99.9 percent particulate removal from low-Btu gas.
II. Liquid Fuels		
A. Extraction of oil from oil shale		[e]Data from Refs. 7 and 8. Major sources of emissions from TOSCO II are shale crushing and fine ore storage, processed shale moisturizing, steam superheating and ball circulation, shale product [illegible], and electricity generation. Overall control level of 99 percent is assumed using induced drafts and baghouses with crushing and storage operations and wet scrubbers on other systems. Higher number is original estimate from Ref. 7. Lower number is revised estimate from Ref. 8. Paraho and in-situ retort emissions taken from Ref. 8 and upgrading emissions added to derive totals.
1. TOSCO II[e]	35-47	
2. Paraho[e]	15	
3. In-situ[e]	20	
B. Liquefaction of western coal		
1. SRC[f]	3	[f]Data from Ref. 3. Assumes western coal as above. Emissions result from combustion of byproduct gases and coal. Emissions from coal thermal dryer reduced 99.5 percent by combination of multiple cyclones and Venturi scrubber.
2. CSF[g]	7	[g]Data from Ref. 1. Assumes western coal as above. Emission from coal and gas-fired power plant reduced 99.5 percent by electrostatic precipitator. Emissions from coal thermal dryer reduced 99.85 percent by multiple cyclones/baghouse combination.
3. H-Coal[h]	13	[h]Data from Ref. 1. Assumes western coal as above. Emissions result from combustion of coal and gas to provide plant steam, heat and electricity. Emissions from coal-fired boiler reduced 99.5 percent by electrostatic precipitator.
C. Liquefaction of midwestern coal		
1. SRC[i]	5	[i]Data from Ref. 3. Assumes 22 million Btu/ton, 3.5 percent sulfur, 11 percent ash midwestern coal. Emissions and controls as in footnote f.
2. CSF[j]	6	[j]Data from Ref. 3. Assumes midwestern coal as above. Emissions and controls as in footnote g.
3. H-Coal[k]	9	[k]Data from Ref. 9. Assumes midwestern coal as above. Emissions result from combustion of gas and coal. 99.5 percent particulate control assumed.
D. Assisted recovery of oil		
1. Micellar flood and CO_2 miscible[l]	<1	[l]By analogy with primary recovery, emissions are small.
2. Steam injection[m]	41	[m]Results from the combustion of residual oil necessary to convert five barrels of water to steam for every barrel of oil recovered. No controls assumed.
III. Pipeline Quality Gas		
A. Gasification of western coal		
1. Lurgi[n]	<1-5	[n]Data from Refs. 3, 4 and 10. Assumes 18 million Btu/ton, 0.8 sulfur, 8.3 percent ash western coal. Lower figure results if coal is converted to low-Btu gas which is then combusted to provide process heat and steam. Higher figure results if coal is burned directly in power plant, using 99.5 percent efficient electrostatic precipitator for particulate control.
2. Synthane[p]	26	[p]Data from Refs. 3 and 11. Assumes western coal as above. Emissions result from combustion of coal and high ash content byproduct char in the power plant, and 99.5 percent particulate removal with an electrostatic precipitator.
3. Hygas (steam-oxygen)[p]	12	
B. Gasification of midwestern coal		
1. Synthane[q]	22	[q]Data from Ref. 3. Assumes 22 million Btu/lb., 3.5 percent sulfur, 11 percent ash midwestern coal. Emissions and controls same as in footnote p.
2. Hygas (steam-oxygen)[q]	11	

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Table VI-3

NO$_x$ EMISSIONS RESULTING FROM
TECHNOLOGIES FOR INCREASING
U.S. ENERGY SUPPLIES

Technology	Tons NO$_x$ per 10^{12} Btu Product Energy	Assumptions
I. Electricity[a]		
A. Direct burning of western coal	1100	[a]Data from Ref. 5. Assumes controlled combustion to achieve federal performance standard of 0.7 lb. NO$_x$/10^6 Btu fuel input.
B. Low-Btu gasification of western coal followed by combined cycle		[b]Data from Ref. 3. Emission from the combustion of 129 Btu/SCF gas in combined cycle assuming NO$_x$ emission rate of 0.021 lb/10^6 Btu.
1. Lurgi[b]	25	[c]Data from Ref. [illegible] 36 percent of emissions are from coal-fired thermal dryer. Remainder is from combined-cycle combustion of 300 Btu/SCF gas resulting in 150 ppm NO$_x$ in stack gases.
2. Koppers-Totzek[c]	47	
3. Fluidized Bed[d]	30	[d]Data from Ref. 6. Emission from the combustion of 157 Btu/SCF gas in combined cycle assuming NO$_x$ emission rate of 0.025 lb/10^6 Btu.
II. Liquid Fuels		
A. Extraction of oil from oil shale		
1. TOSCO II[e]	85-250	[e]Data from Refs. 7 and 8. TOSCO II emissions result from burning a combination of gases, C_4-liquids and fuel oil to provide process steam, heat and electricity. Sources are the same as for SO_2 and particulate emissions. (See Tables XI-1 and XI-2.) Revised (lower) TOSCO II and Paraho and in-situ emissions obtained from Ref. 8 as in preceding tables.
2. Paraho[e]	30	
3. In-situ[e]	40	
B. Liquefaction of western coal		
1. SRC[f]	66	[f]Data from Ref. 3. All NO$_x$ emissions from combustion of a combination of coal and process-derived gases to provide process steam, heat and electricity.
2. CSF[f]	65	
3. H-Coal[g]	160	[g]Data from Ref. 9. All NO$_x$ emissions as in footnote f above.
C. Liquefaction of midwestern coal		[h]By analogy with primary recovery, emissions are low.
1. SRC[f]	66	[i]Results from the combustion of residual oil necessary to convert five barrels of water to steam for each barrel of oil recovered.
2. CSF[f]	61	
3. H-Coal[g]	44	
D. Assisted recovery of oil		
1. Micellar flood and CO_2 miscible[h]	< 1	
2. Steam injection[i]	110	
III. Pipeline Quality Gas		
A. Gasification of western coal		
1. Lurgi[j]	17-130	[j]Data from Refs. 3, 4 and 10. Lower figure results if coal is converted to low-Btu gas which is then combusted to provide process heat and steam. Higher figure results if coal is burned directly in power plant.
2. Synthane[k]	200	[k]Data from Refs. 3 and 11. Emissions result from the combustion of coal and byproduct char to provide process steam, heat and electricity.
3. Hygas (steam-oxygen)[k]	116	
B. Gasification of midwestern coal		
1. Synthane[k]	180	
2. Hygas (steam-oxygen)[k]	110	

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the process which change the emissions significantly. These uncertainties or variations are explained in the footnotes. As explained previously, it is important to use great care in using Tables VI-1 through VI-3 to compare emissions of technologies producing different forms of energy.

If purchased electricity has been incorporated into the plant design, the emissions from generation of this electricity have been added to the plant emissions. We have used emissions corresponding to those released by a coal-fired power plant meeting the federal new source performance standards (1800 tons of SO_2, 150 tons of particulates and 1050 tons of NO_x per 10^{12} Btu of electricity, assuming a conversion efficiency of 33 percent). The processes to which these additional emissions apply are the CSF and H-Coal processes for coal liquefaction, and the TOSCO II process for shale oil production. All other process designs have incorporated on-site electricity generation into the plant operation.

Since emissions of a given pollutant can vary significantly from one technology to another for the same conversion activity (e.g., SO_2 emissions from the SRC and H-Coal processes for western coal liquefaction), it is worth explaining in some detail the origin of such differences where the differences are significant.

In low-Btu gasification of western coal, the advanced fluidized bed gasififer/combined-cycle system is shown to have about 30 percent lower SO_2 emissions than the Lurgi and Koppers-Totzek gasifiers in conjunction with combined cycle operation. This is due to the assumption that a panel bed calcined-dolomite filter (of the type developed by Arthur Squires at the City University of New York) is used to remove H_2S from the fuel gas prior to combustion.[6] The H_2S removal efficiency of this device is somewhat higher than the hot carbonate scrubber assumed for the Lurgi and Koppers-Totzek gasifiers, reducing H_2S to a level of about 10 ppm in gas entering the gas turbine. The device is still in the experimental stage, but it is the type that may be expected to be used in advanced gasifier/combined-cycle operations.

The panel bed filter also has a high removal efficiency for particulates, as seen in Table VI-2. Higher NO_x emissions for the Koppers-Totzek gasifier are due to the coal-fired thermal dryer, which is required to remove moisture from the coal prior to entering the gasifier. In general, the NO_x emissions resulting from combustion of low-Btu gas in a gas turbine have not been well characterized, and the numbers presented in Table VI-3 should be considered only rough approximations.

The higher levels of SO_2, particulate, and NO_x emissions from TOSCO II oil shale processing are derived from Colony Development Operation's initial estimates as presented in Reference 7. More recently, Colony has revised these estimates[8] to reflect their decision to employ a higher degree of hydrotreating of the fuel oil combusted within the plant to reduce its sulfur and nitrogen content, and to apply a higher degree of control on particulate emissions. The lower levels of emissions shown in the tables reflect this change. The higher emission levels have been retained in the tables since companies other than Colony will employ the TOSCO II process, and the levels of controls they will choose to employ have not yet been determined.

The emission levels for the Paraho and in-situ processes are derived from retort emissions as estimated by Engineering Sciences, Inc. in Reference 8 in combination with Colony's revised estimates for emissions from shale oil upgrading. The Paraho and in-situ retort emissions should be considered very rough estimates since no actual operating data have been released on either process. In addition, emissions for shale oil upgrading depend strongly on the types of fuels consumed in the plant, and these are a function of the nature of the byproducts from retorting and other factors. Thus, the total emission estimates for these two processes can only be considered reliable to within a factor of perhaps 2. It is worth noting that the developers of the Paraho process have claimed that emissions are substantially less than those from the TOSCO II process. In addition, in regard to SO_2 emissions from in-situ retorting, it has long been recognized that large quantities of low heating value sulfur-containing gases will be generated by underground retorting and that combustion of these gases will release significant quantities of SO_2.

The wide variations in SO_2 and NO_x emissions among the three technologies for liquefying western coal are due chiefly to the different plant fuel mixes employed in each process. The solvent refined coal (SRC) process generates the largest quantity of byproduct hydrocarbon gases of the three processes. These gases can be treated to remove almost all the H_2S, thus providing a clean source of fuel. Ninety-two percent of the SRC plant fuel requirements (including electricity generation) can be met by the source. For the CSF and H-Coal processes, however, 26 percent and 60 percent, respectively, of the plant fuel requirements must be met by burning coal. Thus, SO_2 emissions are intermediate for the CSF process and highest for the H-Coal process. In addition, particulate and NO_x emissions are higher for burning coal than for burning hydrocarbon gases, so that the H-Coal process is higher in these categories as well.

For midwestern coal liquefaction, the relative order of SO_2 and NO_x emissions is exactly the reverse of the western coal case, and in fact, emissions from midwestern coal liquefaction are actually lower than those from western coal liquefaction for the H-Coal process in spite of the higher sulfur content of midwestern coal. The reason for this is that the H-Coal process utilizes both byproduct hydrocarbon gases and the heavy bottoms fraction of the liquid product as sources of hydrogen for hydrogenating the coal.[9] Due to the higher hydrogen-to-carbon ratio of midwestern coal relative to western coal, somewhat less hydrogen is required for this purpose. Moreover, a higher fraction of heavy bottoms is recovered from the liquid product derived from midwestern coal,[9] thus reducing the dependence on byproduct gases as a source of hydrogen. The result of these two effects is that about an 80 percent greater volume of hydrocarbon gases is available as plant fuel in an H-Coal plant processing midwestern coal than in one processing western coal. In fact, all the plant fuel requirements (except purchased electricity) of the midwestern coal plant are provided by clean-burning hydrocarbon gases, resulting in significantly reduced SO_2, particulate, and NO_x emissions than in the western coal case.

The higher NO_x and SO_2 emissions for the SRC process utilizing midwestern coal relative to those from the CSF and H-Coal processes results from (1) a 40 percent larger plant fuel requirement for the SRC process,[3] and (2) a less efficient Claus sulfur recovery plant for the SRC process due to the dilute H_2S stream entering the plant.[3]

As in coal liquefaction, the differences in emissions among the three technologies for gasifying western coal are due to the plant fuel requirements and the fuel mix characteristic of each technology. As indicated in the tables, the lowest emissions for Lurgi gasification are achieved when some of the coal is gasified to provide low-Btu gas for plant fuel. This is the method that El Paso Natural Gas Company will utilize in its Burnham, New Mexico, coal gasification project.[10] Western Gasification Company (WESCO), on the other hand, plans to burn coal directly in its proposed New Mexico plant and employ stack gas controls to reduce emissions.[12] This type of activity results in the higher level of emissions shown in the tables for Lurgi gasification.

Both the Synthane and Hygas processes burn a combination of coal and byproduct char as plant fuel. A relatively lower amount of char is available in the Hygas process since part of the char is gasified to provide hydrogen-rich gas for coal gasification (see Chapter II). Therefore, a higher proportion of coal must be utilized as plant fuel for the Hygas process relative to the Synthane process. The coal is higher in sulfur content than the char, but the char has a much higher ash content.[3] This explains why the Hygas process has higher SO_2 emissions but lower particulate emissions than the Synthane process for both western and midwestern coal gasification.

The higher NO_x emissions from the Synthane process relative to either the Hygas or Lurgi processes results from a total plant fuel requirement that is approximately 50 percent higher than either of the other two processes.[3]

All of the emission figures in Tables VI-1 through VI-3 were obtained using estimates of reasonable control levels applied to emission estimates made from conceptual process designs, pilot plant operating data, or, in the case of TOSCO II oil shale retorting and Lurgi coal gasification, actual full-scale plant operating plans. These figures are, of course, sensitive to the types of controls applied, the fuel mix employed in each process, and other plant operating factors. These figures should therefore not be considered as "hard" data but as reasonable estimates of the emissions from each process according to the best currently available information.

3. Trace Element Emissions from Burning Western Coal to Generate Electricity: A Simple Model

The purpose of this section is to evaluate the potential impact of trace elements released in coal combustion. The estimated time required to double the natural abundance of trace elements in soil are used as measures of the impact of the emissions. Doubling times are estimated by using a simple model discussed below. Calculations are carried out on trace element emissions from the combustion of coal found in the eastern and western United States in order to provide a regional comparison. No attempt has been made to estimate the ambient air levels.

The calculations of doubling times for trace element concentrations in the soil are not intended to provide an explicit measure of health or ecological impacts. However, they do provide a basis for assessing the importance of trace element deposition from coal burning relative to concentrations found in the terrestrial environment.

Table VI-4 summarizes the available data concerning the moisture-free trace element content of various coals in the United States. The table has been divided into two groups, representing coals of eastern and of western origin.

Table VI-5 presents data concerning the percent of each element emitted to the atmosphere for two coal combustion processes. The percent values given in column one are for a cyclone combustion process[13] and in column two, for a pulverized process.[14] Although these values were obtained from only two sources, they should represent the range of emissions that can be expected in coal combustion. Fulkerson [13] reported that the cyclone plant was equipped with the best "state-of-the-art" emission control technology.

In Table VI-6 the trace element values reported in Table VI-4 are averaged for eastern and western coal. Assuming that the dry weight Btu content is approximately equivalent for the coal from each region[15] the rate of atmospheric release (tons/year) for each element was then computed for a 1000 MW(e) plant* using either the cyclone or pulverized efficiency data. The computation consisted of multiplying the coal burned per year times the concentration and percent emission data (Table VI-5) to calculate the elemental mass emission rate.

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*1000 MW(e) = 2.2×10^{13} Btu/yr. at 75 percent load factor. Assuming a dry weight heating value of 2×10^{7} Btu/ton, 3.1×10^{6} tons of coal (moisture free) are consumed per year.

Table VI-4

MEAN TRACE ELEMENT CONCENTRATIONS (ppm, Moisture Free) OF VARIOUS COALS

		Western Region					Eastern Region			
Element	**S**	Colorado, Valmount Power Station, Boulder^{21}	Montana and Dakotas^{22}	Wyoming Powder River^{23}	Montana Colstrip^{5}	Utah^{24}	Illinois^{24}	Penn.-Ohio-W. Va.^{22}	Tenn. Allen Power Plt.^{13}	Maryland Chalk Pt. Power Plt.^{14}
Beryllium	Be		0.12-3.9	.25*	Trace	1.0	1.9	2.0-3.1	0.3	
Fluorine	F		65	56.5	31.6	66	32-134	50-120		
Arsenic	As			2.1	Trace	0.5	14	3-59	5	25
Selenium	Se	1.9		1.1	0.016	1.2	2.2			5.1
Cadmium	Cd			0.11†	0.23	≤0.2	≤0.2-22	(0.39)^{25}	0.46	
Mercury	Hg	0.07	0.07	0.12	0.15	0.04	0.24	0.12-0.21	0.12	
Lead	Pb	≤5	7	5.3‡	4.8	5	49	4-14	4.9	9.6
Bromine	Br				21.0	23	15		4.3	41
Zinc	Zn	7.3		6.6		10	342	(24.8)^{25}		80
Copper	Cu	9.6	15	13.7	≤100	10	15	14-17		
Nickel	Ni		7	4.0		4	23	9.7-20		25
Chromium	Cr		7	7.7	2.9	7	17	11-15		29
Vanadium	V		16	20.9	2.5	10	34	19-25		40
Barium	Ba			206.3						150
Strontium	Sr	120		52.6						86

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*44 percent of the coal samples contained less than .15 ppm beryllium.

†70 percent of the coal samples contained less than 0.1 ppm cadmium.

‡8 percent of the coal samples contained less than 1.5 ppm lead.

Table VI-5

PERCENT TRACE ELEMENT EMISSION FOR A CYCLONE AND PULVERIZED COAL-FIRED POWER PLANT

(Percent)

Element	Cyclone (Ref. 13)	Pulverized (Ref. 14)
F	50[a]	50[a]
AS	2.8	49
Se	3[b]	49
Cd	3	10[b]
Hg	85	85
Pb	2.8	28
Br	85	85
Zn	2[b]	10.6
Ni	2[b]	10.5
Cr	2[b]	8.4
V	1.1	6.2
Ba	2[b]	8.4
Sr	2[b]	9.1

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[a] Reference 16

[b] Conservative estimate.

Table VI-6

TRACE ELEMENT EMISSION RATE FROM 1000 MW(e) COAL-FIRED POWER PLANT

(Tons/year)

Element	Western Coal			Eastern Coal		
	ppm	Cyclone	Pulverized	ppm	Cyclone	Pulverized
F	44.1	68.4	68.4	85	132	132
As	2.1	0.18	3.21	26	2.25	39.7
Se	0.56	0.05	0.86	3.6	0.33	5.56
Cd	0.17	0.15	0.05	0.43	0.04	0.13
Hg	0.13	0.34	0.34	0.18	0.47	0.47
Pb	5.1	0.44	4.50	16	1.38	13.8
Br	21.0	55.3	55.3	20	52	52
Zn	6.6	0.41	2.2	149	9.23	48.9
Ni	4.0	0.25	1.30	19.4	1.2	6.3
Cr	5.3	0.33	1.38	18.0	1.1	4.7
V	17.2	0.59	3.30	29.2	1.0	5.61
Ba	206.3	12.80	53.7	150	9.3	39.1
Sr	92.6	8.61	26.1	86	8.0	24.3

After atmospheric emission, the transport and fate of the elements depend on environmental conditions (e.g., wind direction and velocity, degree of precipitation, etc.) and the size and density of the emitted particles. The variation in particle size distribution of the different trace elements results in different dispersal and deposition characteristics in and from the atmosphere.[17] In the model, we assume that 80 percent of the particulates are eventually deposited on the surface environment surrounding the plant (115 square miles) through various means (wash-out, fallout, etc.).

Klein and Russell[18] investigated soil enrichment around a coal-fired power plant for various elements and concluded that approximately 80 percent of the mass of iron (Fe), titanium (Ti), zinc (Zn), cobalt (Co), chromium (Cr), copper (Cu), nickle (Ni), cadmium (Cd), and silver (Ag) were deposited within an area of 115 square miles around the plant. Little soil recovery of mercury (Hg), which is emitted as a volatile gas, was reported. Klein and Russell[18] assumed that enrichment is confined to the upper 2 cm of soil, which had a density of 2.7 gm/cm^3. Using these assumptions and a transfer efficiency of 80 percent to the 115 square mile area surrounding a coal-fired power plant, the time required to double the natural abundance of elements within the area can be calculated, if the natural soil concentration is known.[*] Using the average elemental (overburden) concentrations for the Power River Basin,[19] Table VI-7 presents the elemental doubling time for the two coal and plant types within a 115 square mile area.

The doubling time presented in Table VI-7 represents a crude estimate of the trace element impact to the local terrestrial environment surrounding a potential 1000 MW(e) coal-fired power plant. If the calculated doubling time is short for a particular element, one would expect an enhancement of the natural burden of that element, thereby stressing the ecosystem. On the other hand, if the doubling time of a trace element is long, little stress or impact upon the ecosystem would be expected.

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[*] (Soil density) x (area) x (depth) x (ppm element) x (1x10^{-6}) = mass of element in given depth of given area.

Table VI-7

POWDER RIVER TRACE ELEMENT ABUNDANCES AND DOUBLING TIMES BY COAL TYPE AND COMBUSTION PROCESS

			Years to Double Natural Overburden			
			Western		Eastern	
Element	ppm	Tons/ 115 $mi^2 \cdot 2cm$	Cyclone	Pulverized	Cyclone	Pulverized
F	650	11505	210	210	109	109
As	8.3	146	1000	57.5	80	4.5
Se	0.4	7.1	167	10	26	1.5
Cd	0.4	7.1	582	175	217	67.5
Hg	0.1	1.8	6.5	6.5	4.8	4.8
Pb	15	265	750	72.5	240	24
Zn	90	1590	4825	900	215	40
Ni	30	530	1325	508	550	327
Cr	70	1240	4665	1107	1400	327
V	120	2124	4472	800	2640	470
Ba	600	10620	1030	245	1420	337
Sr	130	2301	332	110	357	118

The doubling time index is a rough approximation of impact; it does not account for ambient atmospheric impacts nor does it consider the chemical form of the element. The carcinogenicity of nickel carbonyl and various arsenic compounds, as well as the corrosiveness of hydrogen fluoride, for example, are factors of importance which are not explicitly considered. Table VI-7 indicates that the trace element emissions from western coal, using the pulverized process, are approximately equivalent to eastern coal using the cyclone process that is installed with the best "state-of-the-art" emission control technology. However, trace element impacts from western coal should be significantly less than those observed for eastern coal-fired plants if the cyclone combustion process can be utilized in western coal combustion.

The elements exhibiting less than 100 years doubling time for the western coal-pulverized process, in order of increasing doubling time, are: Hg(6.5), Se(10.0), As(57.5), and Pb(72.5). We have assumed a homogeneous deposition over the 115 square mile area. However, elemental deposition will increase toward the source as well as along predominant wind rows. Thus, the impact of the trace elements will be increased in certain "hot spots." Although it is calculated to have a low doubling time, mercury (Hg) should not present a local problem due to its gaseous diffusion into the atmosphere. Thus, it would be in accord to the deposition pattern presented by Klein and Russell.[18] Mercury emissions, however, may add to the natural levels on a regional scale. Arsenic (As) and lead (Pb), which are generally toxic, nonessential heavy metals, may produce impacts in localized "hot spots" within the deposition zone. Selenium (Se), is an essential heavy metal, but is moderately toxic to plants and highly toxic to mammals.[20]

Assuming that the "hot spots" have doubling times, an order of magnitude less than the general deposition zones and that the power plant operates an average of 20 years, the selenium (Se) concentrations would increase 21-fold, arsenic (As) approximately 5-fold, and lead (Pb) approximately 4-fold in this time.

C. The Relation of Emissions to Air Quality

The levels of emissions of SO_2, particulate matter, and NO_x, which have been tabulated in Section B are indicative of the relative impact on air quality that would result from each energy production option. However, to provide a quantitative estimate of the actual degradation in air quality which would result from each option, detailed dispersion model calculations must be carried out. Such calculations are beyond the scope of this study.

Rough estimates of ambient levels of air pollutants resulting from the emissions shown in Tables VI-1, VI-2, and VI-3 can be made by comparison with the results of dispersion model calculations which have been carried out for similar energy production systems. These calculations have been performed by the Radian Corporation in a study prepared for the Council on Environmental Quality and the Federal Energy Administration.[26] To provide a basis for the dispersion model calculations, detailed assumptions were made by Radian for the energy conversion processes under consideration. These assumptions included the number of emission stacks associated with each process, the height of each stack, the rate of emissions from each stack, the stack gas exit velocity and temperature, and so forth. Such detailed assumptions were not made in this study, nor were they needed to estimate the overall level of emissions from each process. Furthermore, because of different assumptions made in the two studies regarding emission controls, sulfur content of fuels, etc., the overall levels of emissions calculated by Radian are not directly usable in this study. The problem, then, is to scale the ambient air concentrations calculated from emission levels used in the Radian study to those used in this study. In the absence of more detailed information with which to compare the emission levels derived in the two studies, the only reasonable step which can be taken is to scale the ambient air concentrations calculated in the Radian study by the ratio of the overall emission levels obtained in each study for each pollutant species.

Although the above procedure is the only effective one by which ambient air concentrations can be estimated under the limitations of the data and within the scope of the study, certain difficulties should be noted. The major source of error results from the sensitivity of the dispersion model calculations to the distribution of emission sources and the stack parameters associated with them. By using the total level of emissions of a given pollutant species as the scaling factor for ambient air levels, one is assuming the emission level from each source (stack) within a process is scaled by the same factor. In practice, however, the emission levels in this study were derived from certain assumptions regarding fuels combustion and sulfur recovery within each process. Thus, it may be calculated, for example, that 30 percent of SO_2 emissions result from sulfur recovery operations and 70 percent from fuels combustion within a certain process. The Radian study may arrive at a different distribution of emissions because of different assumptions. Thus, emissions from each stack will not scale as the total level of emissions, and the ambient air concentrations calculated on this basis will be somewhat different from those which would be calculated on the basis of the emission source distribution appropriate for the assumptions made in this study.

The calculation of ambient air concentrations from levels of emissions is based on site-specific meteorlogical data--wind direction, wind speed, and atmospheric stability (air temperature versus height above the ground). Three of the sites which Radian used for calculation of ambient air quality, and which were used to derive results for this study, are as follows: Sheridan, Wyoming; Springfield, Illinois; and Grand Junction, Colorado. The former two sites were chosen as representative of areas where coal conversion activities may be carried out in the Northern Great Plains and the Midwest, respectively, while the latter site was chosen to represent the oil shale region. Short-term (3 hour or 24 hour) worst case ambient air concentrations were calculated on the basis of the worst meteorological conditions which could prevail. These are assumed conditions, and are thus not site-specific. However, the maximum annual average concentrations were calculated using meteorological data appropriate for a given site. Other details of the calculations may be found in the Radian report.[26]

Tables VI-8 through VI-16 show the results of the Radian calculations scaled as described in previous paragraphs, and represent ambient air levels resulting from the emissions from a single plant of the size shown in each table. To provide a relative measure of air quality impact, the ambient air concentrations are expressed not as absolute numbers but as ratios of ambient air concentrations divided by ambient air quality standards appropriate to three air quality regions as proposed by the Environmental Protection Agency. A Class I region represents essentially non-degraded air quality, a Class II region represents moderately degraded air quality,

Table VI-8

SO_2 IMPACTS ON AIR QUALITY NEAR A 1000 MW(e) POWER PLANT USING WESTERN COAL

SO_2 Concentration/Ambient Air Quality Standard

Option	3 hr (Worst Case)			24 hr (Worst Case)			Annual Average		
	Class III	Class II	Class I	Class III	Class II	Class I	Class III	Class II	Class I
1. Direct burning in west	0.06–0.24	0.11–0.45	3.1–13	0.04–0.18	0.11–0.47	2.2–9.4	0.01–0.04	0.04–0.17	0.30–1.3
2. Combined cycle in west	0.01–0.02	0.02–0.03	0.64–0.88	0.01–0.02	0.03–0.04	0.62–0.86	0.08–0.01	0.03–0.04	0.23–0.32
3. Direct burning in midwest	0.06–0.24	0.11–0.45	3.1–13	0.04–0.18	0.11–0.47	2.2–9.4	0.01–0.03	0.03–0.11	0.20–0.85
4. Combined cycle in midwest	0.01–0.02	0.02–0.03	0.64–0.88	0.01–0.02	0.03–0.04	0.62–0.86	0.003–0.004	0.01–0.02	0.10–0.12

Table VI-9

PARTICULATE IMPACTS ON AIR QUALITY NEAR A 1000 MW(e) POWER PLANT USING WESTERN COAL

Particulate Concentration/Ambient Air Quality Standard

Option	24 hr (Worst Case)			Annual Average		
	Class III	Class II	Class I	Class III	Class II	Class I
1. Direct burning in west	0.01	0.06	0.17	0.002	0.009	0.02
2. Combined cycle in west	0-0.01	0-0.04	0.001-0.12	0-0.001	0-0.006	0-0.01
3. Direct burning in midwest	0.01	0.06	0.17	0.001	0.006	0.01
4. Combined cycle in midwest	0-0.01	0-0.04	0.001-0.12	0-0.001	0-0.004	0.-0.01

Table VI-10

NO_x IMPACTS ON AIR QUALITY NEAR A 1000 MW(e) POWER PLANT USING WESTERN COAL

Option	Annual Average
1. Direct burning in west	0.02
2. Combined cycle in west	0.001
3. Direct burning in midwest	0.01
4. Combined cycle in midwest	0.0004

Table VI-11

SO$_2$ IMPACTS ON AIR QUALITY NEAR A 100,000 BBL/DAY CRUDE OIL PRODUCTION FACILITY

SO$_2$ Concentration/Ambient Air Quality Standard

Option	3 hr (Worst Case)			24 hr (Worst Case)			Annual Average		
	Class III	Class II	Class I	Class III	Class II	Class I	Class III	Class II	Class I
1. Midwestern coal liquefaction	0.01–0.14	0.19–0.26	5.1–7.0	0.10–0.14	0.26–0.36	5.4–7.5	0.04–0.06	0.16–0.24	1.3–1.8
2. Western coal liquefaction	0.04–0.14	0.07–0.26	2.3–7.4	0.05–0.16	0.13–0.42	2.6–8.2	0.02–0.05	0.08–0.20	0.51–1.6
3. Oil shale*	0.17–0.22	0.32–0.41	8.7–11	0.16–0.21	0.42–0.53	8.4–11	0.06–0.08	0.24–0.32	1.9–2.5
4. OCS oil					Negligible				
5. Alaskan oil					Negligible				
6. Assisted recovery (miscible methods)					Negligible				
7. Assisted recovery (steam injection)					Significant but not quantified				

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* TOSCO II process.

Table VI-12

PARTICULATE IMPACTS ON AIR QUALITY NEAR A 100,000 BBL/DAY CRUDE OIL PRODUCTION FACILITY

Particulate Concentration/Ambient Air Quality Standard

Option	24 hr (Worst Case)			Annual Average		
	Class III	Class II	Class I	Class III	Class II	Class I
1. Midwestern coal liquefaction	0.04–0.07	0.20–0.37	0.61–1.1	0.005–0.01	0.04–0.07	0.07–0.13
2. Western coal liquefaction	0.03–0.08	0.15–0.40	0.46–1.2	0.08–0.02	0.04–0.09	0.07–0.18
3. Oil shale*	0.21–0.29	1.1–1.5	3.2–4.4	0.04–0.06	0.26–0.36	0.52–0.72
4. OCS oil	Negligible					
5. Alaskan oil	Negligible					
6. Assisted recovery (miscible methods)	Negligible					
7. Assisted recovery (steam injection)	Significant, but not quantified					

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* TOSCO II process.

Table VI-13

NO_x IMPACTS ON AIR QUALITY NEAR A 100,000 BBL/DAY CRUDE OIL PRODUCTION FACILITY

NO_x Concentration/Ambient Air Quality Standard

Option	Annual Average
1. Midwestern coal liquefaction	0.01-0.02
2. Western coal liquefaction	0.008-0.02
3. Oil shale*	0.03-0.17
4. OCS oil	Negligible
5. Alaskan oil	Negligible
6. Assisted recovery (miscible methods)	Negligible
7. Assisted recovery (steam injection)	Significant, but not quantified

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* TOSCO II process.

Table VI-14

SO_2 IMPACTS ON AIR QUALITY NEAR A 250 MILLION SCF/DAY PIPELINE QUALITY GAS PRODUCTION FACILITY

SO_2 Concentration/Ambient Air Quality Standard

Option	3 hr (Worst Case)			24 hr (Worst Case)			Annual Average		
	Class III	Class II	Class I	Class III	Class II	Class I	Class III	Class II	Class I
1. Western coal gasification	0.04–0.10	0.07–0.19	2.0–5.1	0.04–0.10	0.10–0.26	2.2–5.4	0.02–0.04	0.08–0.16	0.46–1.2
2. Midwestern coal gasification	0.23–0.38	0.43–0.71	12–20	0.20–0.33	0.52–0.86	10–17	0.07–0.11	0.28–0.44	2.1–3.4
3. OCS gas					Negligible				
4. Alaskan gas					Negligible				

Table VI-15

PARTICULATE IMPACTS ON AIR QUALITY NEAR A 250 MILLION SCF/DAY PIPELINE QUALITY GAS PRODUCTION FACILITY

Particulate Concentration/Ambient Air Quality Standard

Option	24 hr (Worst Case)			Annual Average		
	Class III	Class II	Class I	Class III	Class II	Class I
1. Western coal gasification	<0.001-0.03	<0.01-0.15	<0.02-0.50	0-0.006	<0.001-0.04	<0.002-0.07
2. Midwestern coal gasification	0.01-0.02	0.05-0.10	0.18-0.36	0.001-0.004	0.01-0.02	0.02-0.05
3. OCS gas			Negligible			
4. Alaskan gas			Negligible			

Table VI-16

NO_x IMPACTS ON AIR QUALITY NEAR A 250 MILLION SCF/DAY PIPELINE QUALITY GAS PRODUCTION FACILITY

NO_x Concentration/Ambient Air Quality Standard

Option	Annual Average
1. Western coal gasification	0.001-0.01
2. Midwestern Gasification	0.004-0.01
3. OCS gas	Negligible
4. Alaskan gas	Significant, but not quantified

and a Class III region is one in which air quality is allowed to be degraded up to the EPA secondary standard. Although the non-degradation standards (Class I and Class II) have not yet been implemented, the EPA secondary standard would apply in any case.

The interpretation of the entries in the first row of the first column of Table VI-8, for example, is that SO_2 emissions from a single 1000 MW(e) coal-fired power plant under worst case conditions will result in a maximum SO_2 concentration equal to 6 to 24 percent of the Class III 3-hour standard, 11 to 45 percent of the Class II 3-hour standard, and 3.1 to 13 times the Class I 3-hour standard. The range of values corresponds to the level of emission controls assumed, as explained in the footnotes to Table VI-1. The interpretation of other entries in other tables follows in a similar fashion.

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